Resilient Microgrids for Rhode Island Critical Services

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Stakeholders and subject-matter experts consulted during this study did not review the final report before its publication. Their acknowledgment does not indicate endorsement or agreement with the report's content or conclusions.

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EXECUTIVE SUMMARY

INTRODUCTION

The United States faces a critical national vulnerability: over-reliance on an Electric Power System (EPS) or "grid" that serves us very well under normal conditions but is vulnerable to prolonged disruptions from a range of natural and man-made hazards, despite the historical best practices of regulated utilities. Long duration outages lasting more than one week—and potentially months—are rare, but outage frequency and duration are increasing and the risks of severe disruptions are growing. Worst case plausible scenarios could devastate the economy and harm or kill Americans in numbers not seen since the Civil War. National planning and action to reduce these risks is thus far insufficient to the scale of the problem, and evidently national preparedness for this type of emergency is lacking. A large burden of preparedness falls on state and local shoulders.

The good news is that solutions are available to reduce these risks and provide other benefits as well. Distributed Energy Resources (DERs) such as combined heat and power, solar energy, wind power, energy storage and energy efficiency can deliver energy services at lower cost, risk and pollution than can the grid alone. Growing deployment of these solutions is increasingly economical due to technological innovation and state-level energy policies. Microgrids can integrate DERs with controls and switchgear to enable both grid-connected and grid-independent operations to energize society's critical infrastructure when the power is out, and provide other benefits that help maximize DERs' value during normal "blue sky" operations. State level policies and programs can accelerate deployment of these technologies by addressing barriers in the marketplace and the current legal and regulatory environment.

Several states have undertaken research and funding efforts to support microgrid development, including California, Connecticut, Maryland, Massachusetts, New Jersey and New York. Rhode Island is considering development of a similar program. This report is the deliverable for a consulting contract with the Rhode Island Office of Energy Resources (OER), as requested in solicitation #754979 *Resilient Microgrids for Critical Services*. In the wake of multi-day power outages due to severe weather events in recent years, OER sought consultant support for design of a program intended to enhance the energy assurance of critical infrastructure through deployment of distributed energy resources and other means. This effort draws from lessons learned in other states with similar programs. This report describes technologies, procurement strategies, and polices that can contribute to microgrid development.

Intro section 1.1 Critical facilities are dependent on vulnerable critical infrastructure: Our modern society and economy rely on interdependent "systems of systems" of critical infrastructure. The EPS is arguably the most fundamental of these, in that so many other critical systems rely upon it to sustain functionality. The traditional EPS model of fewer large units of centralized generation capacity connected to remote customers is inherently more vulnerable to disruption than an emerging, more distributed model of many small units of distributed generation located at or close to customers. The centralized model is subject to the loss of larger blocks of generation capacity with fewer points of failure. The distributed model reduces reliance on wires, line losses, and the risk of transmission and distribution disruptions.

Microgrids reflect the epitome of the distributed EPS model. Although microgrids can greatly increase the probability that power will be available during outages, in most cases the EPS provides more reliable service on a day-to-day basis. A grid-connected microgrid benefits from EPS reliability to back up its own onsite DERs, which often are not as reliable as the grid. Yet a microgrid can have a good probability of being operational during any given EPS disruption. Critical facility microgrids are generally less susceptible to severe weather disruptions than is the EPS, if only due to reduced reliance on vulnerable transmission and distribution networks.

Microgrids comprising small numbers of critical facilities could not much reduce the numbers of customer power service interruptions, but they could significantly reduce suffering and improve public health and safety for large numbers of people by maintaining critical services and safe havens during prolonged outages. Microgrids and their DERs can contribute to achieving multiple goals including:

- Least cost procurement of electricity service delivery and EPS operation (*e.g.*, by shedding load, contributing power, or helping defer transmission and distribution system upgrades)
- Reduced facility operating costs
- Enhanced public health and safety
- Protection of vulnerable populations
- Community economic development and resiliency
- Increased deployment of cleaner energy resources
- Energy-related emissions reductions
- Climate change risk mitigation (*e.g.*, via greenhouse gas emissions reduction)
- Climate change risk adaptation (*e.g.*, via critical facility mission assurance)

Intro section 1.3 Risks to the Rhode Island EPS: Hazards that pose risks of long duration power outages (defined here as lasting longer than 3 days) are listed below. Appendix A describes these hazards in more detail, and suggests potential policy responses. Hazards listed in **bold font** are "High-Impact, Low-Frequency (HILF) Events" or "Black Sky Hazards" that can cause very long duration outages (defined here as lasting longer than one week, and potentially for weeks to months). Some Black Sky events can have regional or national effects with potentially catastrophic impacts, such as electromagnetic hazards caused by solar flares or the electromagnetic pulse (EMP) created by a high-altitude nuclear explosion.

<u>Natural hazards</u>

- Weather – Wind: Tree fall, blown debris, **severe storms**
- Weather – Wind: Storm surge, seawater inundation
- Weather – Precipitation: Rain, freshwater inundation
- Weather – Precipitation: Snow, **ice**
- Weather – High heat, drought, wildfires

- Geologic/Seismic – Earthquake, **tsunami,** volcano
- **Space weather – Solar flare / coronal mass ejection (CME) / geomagnetic disturbance (GMD)**
- Pandemic

Manmade hazards

- Aging infrastructure, equipment failure
- Human error, accidents
- **Physical attack**
- **Cyberattack**
- **Intentional Electromagnetic Interference (IEMI) attack**
- **Nuclear weapons – Electromagnetic Pulse (EMP) attack**
- Nuclear weapons – **War,** terrorism, dirty bombs

National Grid is the electricity distribution company (EDC) serving ~99% of RI customers. The RI Energy Assurance Plan (RIEAP) states: "National Grid's system contains a considerable amount of redundancy and system protection to minimize the impact of events to its customers…. National Grid's electric system is reported to be designed to withstand the loss of any single high voltage element (*e.g.*, transmission lines, transformers or power plants) without any impact to customers, which is compliant with NERC standards."[1] National Grid also is the state's only natural gas Local Distribution Company (LDC) and maintains redundant pipeline and storage capacity for system reliability and resilience, including for RI's power generation which is almost entirely dependent on natural gas supply.[2]

Despite best practices, any EDC is vulnerable to hazards that can cause prolonged outages. Severe weather events and other natural and man-made disasters pose challenges that are almost impossible for grid operators to overcome.

PART A: RHODE ISLAND CRITICAL INFRASTRUCTURE

Section A1 What is a critical facility?: Critical facilities can be categorized by ownership as being either public sector or private sector. Typically, the public sector is responsible for public health and safety, although companies can play key roles. Companies provide vital services to the community that can be particularly valuable during prolonged power outages. Most state microgrid programs consider the following facility types to be mission critical:

- Continuity of government functions: Municipal centers, public works
- Public safety: First responders, emergency operations centers, emergency shelters
- Health: Hospitals, clinics, pharmacies, dialysis centers
- Potable water supply, wastewater treatment facilities and networks

[1] RIEAP, p.9-8.
[2] RIEAP, p. ES-7.

- Residential facilities where vulnerable populations can shelter in place: multifamily housing, nursing homes, corrections facilities
- Fuel and energy supply: Gas stations, delivery terminals, storage facilities
- Communications and information technology: Cell phone towers, radio masts, internet servers, data centers
- Transportation: Train and bus stations, airports, maintenance facilities
- Food supplies: Supermarkets
- Access to funds: Banks, ATMs

The Rhode Island Emergency Management Agency (RIEMA) has developed a comprehensive Rhode Island Critical Infrastructure Program Plan (RICIPP) based on the USDHS criteria and classifications. RIEMA modeled its definition of critical infrastructure and Key Resources (CIKR) on the Patriot Act terminology:[3]

> "Critical infrastructure includes those assets, systems, networks, and functions—physical or virtual—so vital to Rhode Island that their incapacitation or destruction would have a debilitating impact on security, economic security, public health or safety, or any combination of those matters."

RIEMA added two sectors (Emergency Services and Information Technology) to the four designated by NIAC, for a total of six Life Line Sectors out of the sixteen CIKR sectors; see Figure A-2.[4]

Figure A-2: Rhode Island Critical Infrastructure and Key Resource sectors

Life-Line Sectors	Remaining Sectors
• Communications	• Agriculture & Food
• Emergency Services	• Banking & Finance
• Energy	• Chemical & Hazardous Materials Ind.
• Information Technology	• Commercial Facilities
• Transportation Systems	• Critical Manufacturing
• Water & Waste Water Systems	• Dams
	• Defense Industrial Base
	• Government Facilities
	• Health Care & Public Health
	• Nuclear Reactors, Materials & Waste

Image courtesy John McCoy, RIEMA.

RIEMA has convened a multi-stakeholder process to develop Sector-Specific Plans (SSPs) to identify CIKR facilities and interdependencies, assess hazards and prioritize protection initiatives. Each sector has a designated Sector Lead Agency (SLA). A database of critical facilities is under development, including stakeholder working group input from each of the 16 sectors to help identify critical facilities.

[3] John McCoy, RIEMA, personal communications, Feb. 2nd, 2016.
[4] John McCoy, RIEMA, personal communications, Mar. 2nd, 2017.

Many of these facilities are represented in the Rhode Island Geographic Information System (RIGIS) software. The RIGIS critical facility database can be used to inform microgrid planning, for example by depicting flood zone locations, or determining the type and location of proximal critical facilities that might be considered for inclusion in a microgrid.

Section A2: Critical facility prioritization: Two approaches to microgrid program implementation have differing implications for how OER might apply prioritization criteria: A "Bottom Up" approach that solicits funding applications from eligible projects (*e.g.*, via RFP), and a "Top Down" approach where the OER team identifies critical facilities for targeted outreach. The approaches are not mutually exclusive and can be implemented in a parallel and complementarily manner. Both approaches evaluate and rank applicant projects according to qualitative and quantitative attributes, and fund projects with the best cost/benefit ratio or highest score. Prioritization information sources include:

RIEMA information. Life Line sector facilities are prioritized over other sectors; within each sector SSPs and SLAs are designating priority facilities. CIAT scores indicate criticality of surveyed facilities.

Policy recommendation: OER could require facilities that apply for microgrid program funding to complete a RIEMA CIAT survey. The survey's energy-related questions could be expanded to collect additional energy assurance information such as annual energy use and cost; critical loads including mission-critical energy-using systems and HVAC systems type; BUG characteristics (*e.g.*, size or fuel type, or presence of additional onsite distributed energy resources (*e.g.*, solar photovoltaics or combined heat and power systems). Microgrid funding applications could also collect this type of information.

Cost-Benefit Analysis (CBA). CBA calculations provide Key Performance Indicators (KPIs), such as $/kW of DER capacity, which could inform microgrid project evaluation. (See Part C for further discussion.)

Indirect, non-traditional or "macroeconomic" factors. Microgrids and DERs convey numerous "bigger picture" costs and benefits that typically are not reflected within standard microeconomic project financial analysis, can be hard to quantify, and often are not readily monetized. Docket 4600's Total Resource Cost Test organizes benefit/cost aspects according to where the effects accrue: Power System Level, Customer Level and Societal Level. These "beyond the customer meter" factors include, but are not limited to:

- Costs savings and reductions for grid operators and ratepayers
  - Dispatching microgrid generation provides peak load reduction or local voltage support, resulting in avoided or deferred grid capacity additions or operations and maintenance costs in transmission, distribution and substation assets
  - Reduction in system "line losses"
  - Reduction in electricity prices due to reduced demand
- Avoided costs of outages for critical facilities, local businesses, communities and insurers
- Avoided costs of emissions for cleaner DERs

  - Criteria pollutant reductions
  - Social cost of carbon
  - Improved local air quality
- Public health and safety benefits
  - fewer deaths and injuries during disruptions or due to emissions
- Safe shelter for vulnerable populations / demographics
  - Low to moderate income
  - Children and elderly
  - Disabled, medically dependent
  - Domestic violence shelter
  - Transitional housing, corrections
- Geographic preferences
  - Dispersion across state
  - Location in HUD or USDA funding-eligible area
  - Avoidance of flood zones)
- Economic development benefits
  - Local job creation
  - Technological innovation
  - Attraction of industries with power reliability and energy services
- Contribution to meeting State goals
  - Deployment of renewable energy in State facilities
- National security benefits
  - Reduced oil dependence
  - Increased cybersecurity

There are two primary options for quantifying these types of factors for the purposes of an OER microgrid program, "Economic Valuation" and "Point Scoring" (see Section C1 for further discussion):

- *Economic Valuation method*. Macroeconomic factors could be assigned monetary value using reference criteria such as are contained in Docket 4600's Total Resource Cost Test, or the NY Prize CBA tool. This approach provides more objective, precise (if not accurate) information that can be integrated with "microeconomic" analysis using a dollar value common denominator. Valuation of program goals in dollar terms can be complex and more subjective, such as the added value when a microgrid serves a low to moderate income demographic. Developing this detailed analysis is more resource-intensive for both the program and its participants. If this approach is taken, OER should provide a detailed template and guidance for applicants to apply the appropriate conversion factors to their project, and/or support applicant CBA with funding or technical assistance teams.
- *Point Scoring method*. A streamlined scoring process with abstracted values representing macroeconomic factors and program preferences could simplify evaluation of funding applications. This approach provides information that is more subjective and less accurate, precise and detailed than the Economic Valuation method, and cannot be integrated with "microeconomic" analysis in monetary terms but rather is used in

parallel. This abstracted analysis is less resource-intensive for both the program and its participants. If this approach is taken, the OER team could score funding applications based on information provided in the applications.

<u>Policy recommendation</u>: OER should use the Point Scoring method to simplify the process and conserve program and project resources. This authors suggest a scoring template in Table C-1, which OER can modify as desired.

Public Track and Unique Asset Track options. The basic structure of all the state microgrid programs to date (*e.g.*, CA, CT, MA, NJ, NY) has been to make available funding and other support to eligible applicants via a competitive solicitation. OER could consider a complementary approach to provide more targeted support to unique assets and critical facilities that the Governor can call upon during emergencies.

<u>Policy recommendation</u>: OER could have a two-track approach to identifying and prioritizing critical facilities in a microgrid program: a bottom-up "Public Track" and a top-down "Unique Asset" track.

The "Public Track" approach would be similar in structure to other state microgrid funding programs. Most of the recommendations of this report are intended to inform creation of this type of program. OER could issue an RFP solicitation for municipalities and other critical facility owners to apply for microgrid funding support. This "bottom-up" approach would allow any project that meets the RFP-specified criteria to respond. Applications would be scored based on criteria including a cost/benefit analysis, and a scoring factors that reflect OER program objectives.

A complementary "Unique Asset Track" would take a "top-down" approach: OER would convene an Interagency Working Group (IWG) that includes RIEMA and other agencies as appropriate. The IWG would identify highly critical facilities that provide or enable unique assets and services during a declared emergency. These Unique Assets (UAs) could include, but are not limited to:

- State Emergency Operations Center
- National Guard specialized ground units and armories (*e.g.*, mobile generators, fuel tankers, engineers with heavy equipment, communications, water purification, mobile hospitals, etc.)
- National Guard and other state-owned rotary- and fixed-wing aviation assets
- State agency specialized first responder teams (*e.g.*, collapse rescue, canine, search and rescue, hazardous materials and radiological incident emergency response, Explosive Ordinance Disposal, marine rescue and spill response, etc.)
- State-owned or quasi-public transportation UAs (*e.g.*, airports)

The IWG would reach out to Unique Assets (UAs) and offer funding or other assistance to encourage microgrid development. Track implementation options include:

A. UAs could be solicited to participate in the Public Track application process, and could receive a preferential scoring factor.
B. The UA Track could be conducted as a separate parallel effort to the Public Track, with discrete dedicated funds and outreach.

UAs would be asked to assess their energy assurance strategies, capabilities and facility dependency. If a UA is highly dependent on its base facility, that location could be prioritized for microgrid assistance. If a UA is not facility-dependent due to its ability to relocate personnel and equipment to another location and sustain mission-critical operations, the UA should verify its energy assurance strategy and capability to sustain operations beyond 72 hours at alternate locations. For example, if a specialized team's base facility loses power, and the team can move to an alternate location or staging area, what is that alternate location's grid-independent energy assurance?

Policy recommendation: OER could prioritize energy assurance for private sector facilities that enable service restoration for the EPS, natural gas and other critical infrastructure networks.

CI interdependencies: The EPS depends on the natural gas system, and *vice versa*. RI is almost entirely dependent on natural gas supply for electricity generation, with ~97% of in-state generation capacity fueled by natural gas.[5] Power production comprises ~58% of RI natural gas consumption, with industry using ~8% and other retail customers ~34%.[6] "Natural gas-fired generators in Rhode Island do not receive firm gas transmission. Similar circumstances are anticipated in nearby states. Consequently, a disruption in the supply of natural gas would affect electric supply."[7] It is important to note that gas supply capacity and redundancy provide significant resilience; the non-firm gas supply contracts of the power stations render them more vulnerable to curtailment.[8]

Policy recommendation: OER could consider requiring natural gas fueled microgrids to secure firm supply contracts.

National Grid is the only Local Distribution Company (LDC) for natural gas delivery in the state; it does not produce any gas. There are no natural gas wells in RI. Pipelines provide ~93% of the state's supply[9], and RI is effectively at the "end of the line". Two primary pipelines coming through New York state, each with two offshoot lateral lines, supply ~72% of the state's natural gas and also deliver the ~20% of gas coming from Canada [10]: Algonquin Gas Transmission (AGT) provides ~60% of pipeline capacity and Tennessee Gas Pipeline (TGP) provides ~40%.[11]

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[5] RIEAP, p. ES-7.
[6] RIEAP, p. ES-9.
[7] RIEAP, p. 9-10.
[8] For further discussion see RIEAP pp. 9-13 & 9-14.
[9] RIEAP, p. ES-10.
[10] RIEAP, p. ES-10. The same source states on p. ES-12 that AGT and TGP provide 77% of the state's natural gas.
[11] RIEAP p. 3-5.

Pipelines are more resilient against severe weather events than are the overhead EPS transmission and distribution (T&D) networks, which are more exposed to wind, precipitation and inundation hazards. In the event of a cyberattack the pipelines can be operated in manual mode.[12] A major failure that halts supply on either AGT or TGP could take 16–18 months to repair.[13] AGT and TGP rely on compressor stations to maintain supply, which require electricity to operate. Pipeline and lateral redundancy enable the LDC to endure the loss of two compressor stations before it curtails peak day deliveries.[14]

Liquid natural gas (LNG) imports provide ~7% of the state's supply.[15] LNG storage provides a vital buffer and swing supply capacity to help meet short-term demand peaks that exceed pipeline supply capacity. The LDC maintains LNG storage sufficient for ~13 days of peak discharge output.[16]

Liquid fuels: Liquid petroleum fuels—particularly gasoline, diesel fuel and building heating oils—provide critical energy services. Supply disruptions ripple through other critical infrastructure and services, and hinder other community and economic functions. Rhode Island's liquid fuel supply chain is vulnerable to disruptions, particularly storm surge. The concentration of 5 of the state's 6 terminals and 90% of the storage capacity along the Providence waterfront increases geographic risk.[17] OER's microgrid program could address a major vulnerability by installing DERs well above storm surge levels to enable grid-independent terminal operations. As of 2014, none of the terminals had on-site BUGs capable of supporting operations.

Policy recommendation: OER could prioritize petroleum marine terminals and storage facilities for microgrid support, *e.g.*, by preferential scoring and/or including them in a Unique Asset Track.

Downstream of the terminals, petroleum delivery relies on tanker trucks, so the distribution network can function if the terminals are operating and the roads are passable. Storage capacity provides a time buffer if the terminals cannot operate but storage facilities are operable and roads are open. "Rhode Island's petroleum wholesalers report that average inventory levels [are] sufficient to meet the State's needs for approximately two (2) to three (3) weeks."[18]

Gas stations are the vital interface between the gasoline and diesel supply chain and the public. Retail service stations utilize electricity to operate pumps for fueling vehicles. It is uncommon for service stations to have a backup generator. "Consequently, a prolonged electric outage would effectively close all retail service stations and preclude vehicles from being re-fueled….

[12] RIEAP p. 4-21.
[13] RIEAP p. 9-11.
[14] RIEAP, p. 9-12.
[15] RIEAP p. ES-10.
[16] RIEAP p. 9-13.
[17] RIEAP p. 9-15.
[18] RIEAP, pp. 9-15 and 9-17.

Rhode Island is not prepared to respond to such impacts."[19] This situation presents an opportunity for OER to enhance service station energy assurance with sector-specific dedicated microgrid support.

Policy recommendation: OER could prioritize service stations for microgrid support, *e.g.*, by preferential scoring and/or including them in a Unique Asset Track focused exclusively on gas stations.

PART B: MICROGRIDS TECHNOLOGIES AND APPLICATIONS

Section B1 – Definition: There are numerous definitions of "microgrid." The U.S. Department of Energy (DOE) Microgrid Exchange Group definition is perhaps the most widely referenced: "A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode."

Definitions of microgrid types, configurations and ownership models are discussed in more detail in Section B3 and B7. For the purposes of this Part of the report, we reference the microgrid typology suggested by the New Jersey Board of Public Utilities (NJBPU)[20], with minor modifications:

Microgrid type	DERs	Facilities	Meters	Facility owners
Level 1 single facility	1–2+	1	1	1
Level 2 campus	1–2+	2+	1–2+	1
Level 3 multi-user community	1–2+	2+	2+	2+

Section B2 - General purpose: Microgrids serve many purposes and provide multiple services and benefits, including:

- Energy assurance for critical facility mission assurance, continuity of operations and resilience.
- Reduced outage costs.
- Facility owner cost reduction and/or revenue generation.
- Grid operator cost reductions and lower customer electricity costs.
- Increased deployment of renewable resources and improved environmental quality.
- Avoided grid losses and improved DER utilization.
- Greater local control over energy resources.

Applications: Level 1 single-facility microgrids include all critical facility types and are typically used primarily for energy assurance and secondarily to maximize DER benefits during "blue sky" normal operation. Level 2 campus microgrids most commonly include military

[19] RIEAP p. 9-17.
[20] NJBPU, *Microgrid Report*, 2016, p.17.

bases, higher education campuses, health care complexes, high-density residential developments, industrial parks, and remote or island communities, as well as corporate campuses and prisons. Utility cost benefits and energy assurance are primary objectives. Level 3 multi-user community microgrids are very rare although several projects are under development. Applications include provision of electric service at the community scale when connection to a larger "macrogrid" is too costly or otherwise prohibitive (*e.g.*, remote communities or islands); and energy services management at the local scale.

The Minnesota microgrid report described microgrid applications by organizing critical facilities into three asset categories, defined by the critical mission: crisis response and management; public health and safety; and basic needs and services. See Figure B-2.

Figure B-2: Microgrid Applications by Critical Facility Asset Categories[21]

Asset Category	Examples	Priorities and Microgrid Factors
Crisis Response and Management	■ Utility and transportation crew dispatch, supply, and staging centers ■ Government command and control centers ■ Telecom infrastructure	■ Critical to facilitate repair and recovery, minimizing the damage from a crisis and avoiding cascading effects on interdependent systems. ■ Microgrids can be more effective when crisis management facilities are clustered together, allowing asset sharing and load diversity.
Public Health and Safety	■ Hospitals and other health care facilities ■ Police and fire departments ■ Public water systems	■ Vital to support first response, medical care, and law and order. ■ Many such facilities already have backup power systems that can be upgraded with microgrid technologies to increase their effectiveness.
Basic Needs and Services	■ Storm shelters and temporary housing ■ Grocery stores ■ Fuel infrastructure, including gas stations ■ Public transportation and transit systems	■ Vital products and services to support basic needs of residents, and provide shelter and vital mobility for displaced and at-risk populations. ■ Load-management systems and protocols can help conserve fuel and extend effectiveness of basic backup power supplies.

Figure 1-2: Energy Assurance Priorities and Microgrid Applications

Section B3 Types: This section describes microgrid types with examples, including:

- Remote microgrids: Islands, remote communities and commercial installations (e.g., mines).
- Level 1 microgrids: Single- or multiple-DER, Single facility, single owner, BTM installations.

[21] Microgrid Institute, *Minnesota Microgrids: Barriers, Opportunities, and Pathways Toward Energy Assurance*, 2013, p. 17.

- Level 2 campus microgrids: Single- or multiple-DER, multiple facility, single owner installations.
- Utility owned/operated microgrid.
- Utility distribution microgrids—Hybrid ownership model.
- Virtual microgrids.
- Level 3 Multi-user community microgrid.

Section B4 Overview of Microgrid Technologies: This section describes the following topics in detail, with references for further discussion.

Demand Side – Critical Loads: Critical facilities (CFs) support critical missions, which requires that the facility have energy supply for its critical loads (CLs) to enable personnel to remain in the CF and operate essential equipment. This is the primary purpose of a CF microgrid. The mission determines what loads are critical. Most CFs have a common set of "core loads" that enable occupants to remain indoors in safety and comfort, *e.g.*, life safety systems, lighting, HVAC, potable water supply, and wastewater removal. Requirements for maintaining safe indoors temperatures under the extremes of four-season conditions should be considered, and can be met using both passive and active measures.

Further considerations include load shedding and isolation, DER sizing, energy efficiency. Load characteristics inform DER selection and microgrid design. Some specialized equipment such as sensitive electronics have low fault tolerance and require high power quality. DERs must be capable of following the CF load as it changes up or down in island mode, including spikes of inrush current on device start-up. Microgrids that include multiple CFs should consider the complementary aspects of each facility's energy requirements and load profile that can inform economic DER selection and operation. DERs for facility load reduction include solar thermal and heat pump technologies.

Supply Side – Distributed Generation: DG can be categorized according to whether or not the device has rotating equipment (*i.e.*, shaft power), the device's ability to operate in grid-independent mode, and by operating modes: emergency, base load and intermittent generation. Common DG types are depicted in Figure B-3.

Figure B-3: DG Technologies[22]

	DG Technology	Typical Module Size
Nonrenewable	Combined cycle gas turbine	35–400 MW
	Internal combustion engines	5 kW–10 MW
	Combustion turbine	1–250 MW
	Micro-Turbines	35 kW–1 MW
	Fuel cells	1 kW–5 MW
	Stirling engine	2-10kW
	Reciprocating engine	5 kW–50 MW
Renewable	Small hydro	25 kW –10 MW
	Wind turbine	200 W–5 MW
	Solar electric	20 W–100 kW
	Solar thermal	1–80 MW
	Biomass	100 kW–20 MW
	Geothermal	5 kW–100 MW
	Ocean energy	100 kW–1 MW

Section B4.2 DG technologies in microgrid applications: This section includes both selections from other reports and the authors' comments on some of the advantages, limitations and potential strategies regarding common DG technologies in microgrid applications. Examples include:

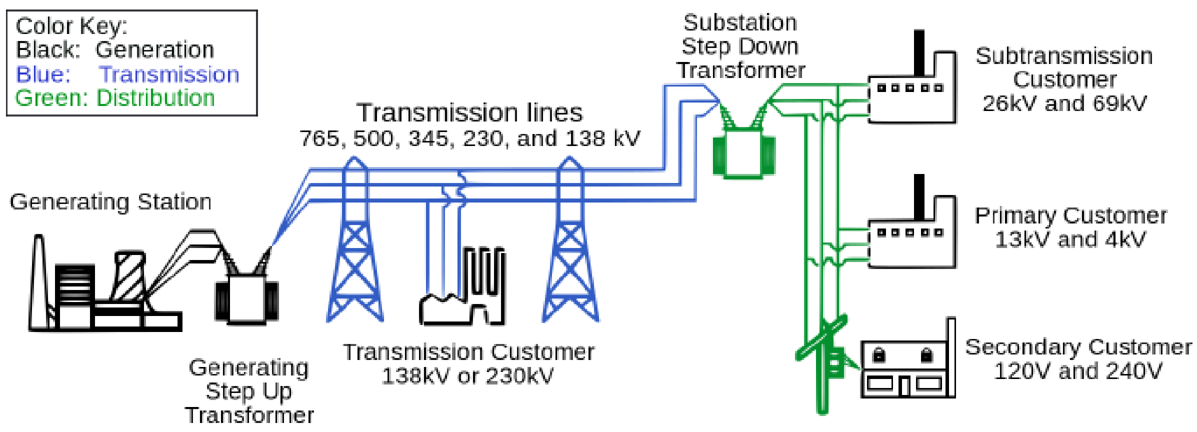
- Standby Backup Generators
- Base Load Constant Duty Assets: Combined Heat & Power
- CHP Prime Movers: Steam Turbines
- CHP Prime Movers: Natural Gas Turbines
- CHP Prime Movers: Microturbines
- Solar Photovoltaic Power
- Energy Storage
- Wind Power
- Hydropower

B4.3 - Microgrid interconnection, controls, and operational considerations: This section discusses microgrid's core technical and operational considerations, driving factors in microgrid design and configuration of its relationship with the larger grid to which it is connected. Put colloquially: this is the hard part of microgrid design and operation, and controls are the special sauce that enables safe and economical operation.

[22] NYSERDA 2014, p. 10.

Electricity distribution infrastructure in grids and microgrids: Figure B-6 depicts the major components of the “macrogrid”. The EPS is defined as the medium- to lower-voltage (at or below 69 kV) distribution portion of the network, depicted in green.

Figure B-6: Electric Grid Systems Components[23]



The EDC owns and manages this segment connecting higher-voltage transmission with low-voltage customers; the EPS stops at the customer meter. EPS infrastructure is akin to that contained within (some) microgrids, albeit on a smaller scale and often at lower voltages. Both the EDC and microgrid owners have similar tasks and objectives for electric power generation and distribution in a safe and reliable manner, with comparable tools and equivalent concerns about system resilience in the face of faults, accidents, and insults such as severe weather.

Above-ground or overhead EPS and microgrid distribution infrastructure hardening techniques and technologies are similar. Hardening the entire EPS would be very expensive, and localized equipment damage could still cause widespread outages. Microgrids are a cost-effective approach to enhancing EPS and community resiliency without extensive and expensive EPS hardening; plus microgrids can provide a host of benefits that buried wires cannot.

This section B4.3 discusses important technical issues in some detail with extensive references to, and excerpts from, other sources.

- *Meters*. Meters play a number of technical and economic roles in microgrid development and operation.
- *Point of common coupling (PCC) of a microgrid to the EPS*. This is the electrical interface between the macrogrid and a microgrid.
- *Interconnection standards such as IEEE 1547*. This vital standard addresses a range of technical requirements and considerations for microgrid operation and interconnection with the EPS. IEEE is revising this standard to include microgrids, expected by 2018.
- *Synchronization of microgrid and EPS*. This is an essential set of issues for microgrids to

[23] NJBPU 2016, p. 45.

safely disconnect from, and reconnect to, the EPS. We describe three strategies: active synchronization, sync check, and open transition (the last being generally the simplest and safest).

- *Voltage control and power control*. This is a primary challenge in microgrid operation.
- We reference a NYSERDA report for discussion of metering and monitoring locations and key parameters for safe operation; strategies for supplying critical loads; and black start considerations including cold-load pickup and inrush current.
- *Inertia*. This is an important stabilizing factor in the grid that poses challenges for microgrids.
- *EPS circuit types and implications for microgrid interconnection*. We reference a NYSERDA report for excellent detailed discussion of microgrid operation where connected to (rural) radial, (suburban) loop, and (urban) spot and grid networks.
- *Controls*. We discuss microgrid controls systems types and functionalities, with consideration of centralized *vs*. decentralized strategies, primary-secondary-tertiary levels of control, microgrid energy management, and complexity and interoperability issues.

Section B5 discusses microgrids' technical and economic performance characteristics.

Section B6 outlines microgrid benefits and value streams. Microgrid benefits (and costs) accrue to different parties: some to the owner, some to the utility, some to society. Not all benefits can be monetized. Different microgrid procurement "business models" provide varied opportunities to monetize potential mixes of value streams. Where and how microgrids provide value depends upon the specific assets and aspects of a microgrid. Distributed generation (DG) is a "prime mover" of value; controls enable islanding, optimal economic dispatch of generation, demand response (DR) and ancillary services revenue; energy storage (ES) provides greater frequency regulation capabilities. These components contribute to the microgrid value chain. Value streams that are available to the microgrid/DER owner could be included in cost/benefit analysis (CBA). Benefits are categorized as both directly and indirectly monetizable; safety and security; public and environmental health benefits; and additional community benefits.

Section B7 highlights microgrid ownership, procurement and financing strategies and business models. Different owner types have different options. Facility-owned or utility-customer-owned options include direct purchase; Rhode Island Infrastructure Bank (RIIB) Commercial Property Assessed Clean Energy (C-PACE) financing; Energy Savings Performance Contracts (ESPCs). Third-party ownership models include Power Purchase Agreements (PPAs) and Energy Services Agreements (ESAs); note that some third party ownership models could challenge the EDC's monopoly franchise and/or require PUC regulatory oversight. Potential options that (probably) require enabling legislation or other precedent approval include community ownership, Energy Improvement Districts (EIDs) or similar structures, and utility full- or hybrid-ownership models.

Section B8 outlines market barriers to microgrid development. These are categorized in terms of real or perceived risks that are legal, administrative, organizational, technical and economic.

Section B9 provides a brief overview of microgrid market status, which can be considered both in terms of the market maturity of microgrid components, and microgrid development. Legal and regulatory barriers and high cost pose formidable barriers to rapid adoption. State policies and programs have a strong influence on the marketplace, and grant-funded programs have had varied success yet account for a large share of recent installments. There is much buzz about microgrid growth, but the sheer scale of marginal investment are small. Slow growth, large potential, and significant impacts of policy levers will shape the marketplace.

Section B10 references case studies and DER data that provide microgrid cost information. Section B11 discusses alternatives to microgrids, including critical mission assurance strategies that are not necessarily tied to a dedicated facility; and trade-offs in cost and complexity between creating multiple Level 1 single-facility microgrids rather than connecting them to form one Level 2 campus microgrid microgrid, as well as between enhanced standby generation *vs*. installing constant-duty DERs.

PART C: COST/BENEFIT ANALYSIS OF CRITICAL INFRASTRUCTURE MICROGRIDS

Section C1 describes a cost-benefit analysis (CBA) framework. An OER microgrid program needs a standardized CBA framework to help compare projects on an equivalent basis and allocate finite resources, and this report is tasked with recommending a methodology.

Each microgrid will have project-specific features that shape the CBA, including ownership structure, procurement strategy and investment vehicle(s), sources of supplemental funding, operating modes, and other considerations. The CBA framework should utilize standard "microeconomic" financial methods and metrics used in energy and facility capital investment projects, to help align the program with the marketplace. In addition, OER wants to consider "macroeconomic" costs and benefits that extend beyond the project to affect the grid, society, the economy and the environment. The authors describe below two primary options for a programmatic approach to quantifying macroeconomic factors: "Economic Valuation" and "Point Scoring" methods.

Economic Valuation method: Macroeconomic factors are assigned monetary value using reference criteria such as are contained in Docket 4600's Total Resource Cost Test, or the NY Prize CBA tool.[24] This approach provides more objective, precise (if not accurate) information that can be integrated with "microeconomic" analysis using a dollar value common denominator. Valuation of program goals in dollar terms can be complex and more subjective, *e.g.*, the added value when a microgrid serves a low to moderate income demographic. Developing this detailed analysis is more resource-intensive for both the program and its participants.

Policy recommendation: If OER prefers to use the Economic Evaluation method, the program should use the NY Prize CBA template, and where applicable modify the conversion factors to use Docket 4600 or other state-specific approaches. OER should provide applicants with a detailed CBA template and instructions, as well as feasibility analysis funding and/or technical support sufficient to the task.

[24] See "NY Prize Community Microgrid Benefit-Cost Analysis Information" section and links at: https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize/Resources-for-applicants

Point Scoring method. A streamlined scoring process with abstracted values representing macroeconomic factors and program preferences could simplify evaluation of funding applications. This approach provides information that is more subjective and less accurate, precise and detailed than the Economic Valuation method, and cannot be integrated with "microeconomic" analysis in monetary terms but rather is used in parallel. This abstracted analysis is less resource-intensive for the program and its participants. If this approach is taken, OER could score funding applications based on information provided in the applications. The authors provide an example of a scoring system in Table C-1, which OER can modify as desired.

Policy recommendation: An OER microgrid program could develop a tool similar to (but more refined than) the author's spreadsheet-based CBAM tool, complemented by the Point Scoring method to simplify the process and conserve program and project resources.

Section C2 describes the author's Cost-Benefit Analysis Model (CBAM) tool, which was based on the CBA tool developed for the NY Prize microgrid program.[25] The CBAM tool is attached to this report for OER use only. This tool is not for public use, and is provided to OER to serve as a conceptual template for development of a comparable but more complex and refined tool; development of such a finished tool is beyond the scope of this report. The CBAM tool provides information that can be used to develop a microgrid project *pro forma* as part of a funding application, similar to that employed by the CT DEEP microgrid funding program Round 3 RFP,[26] which the authors recommend as an OER program application template. See Section E for case study applications of the CBAM to pilot project candidate facilities.

Section C2.3 describes how the CBAM tool can be used to assess grant award amounts according to different funding strategies, including "Eligible Equipment," "Capital Contribution" and "Credit Enhancement" approaches described below.

Eligible Equipment. OER could award grants based on eligible equipment. This categorical equipment-based approach has the advantages of being consistent and equitable in application, and the potential disadvantage that the grant amount might not be sufficient to ensure project gets financed and built. The CT microgrid program Rounds 1 and 2 funded only electrical infrastructure such as circuits/wires, transformers, switchgear, point of common coupling, controls, etc. but did not fund generation; Round 3 of the program allows funding of generation and energy storage. Funding microgrid electrical architecture but not generation is reasonable, because the former does not directly produce cost savings or revenue while the latter can reduce costs and is eligible for a variety of distributed generation policy and economic incentives.

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[25] See "NY Prize Community Microgrid Benefit-Cost Analysis Information" section and links at: https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize/Resources-for-applicants

[26] http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/69dc4ebaa1ebe96285257ed70064d53c?OpenDocument

Capital Contribution. OER could contribute capital to a microgrid project sufficient to enable it to be financed by an applicant-designated procurement model or investment vehicle (*e.g.*, 25 year term ESA, 20 year C-PACE assessment, or 15 year ESPC). This approach has the potential advantage of conserving program funds in cases where a modest contribution could spur project financing and leverage private investment, perhaps at lower program expenditure than an equipment-based approach. It has the disadvantages of inconsistency and potential inequity in application among various candidate projects, as well as project- and owner-specific financial criteria such as acceptable and available simple payback (SPB) periods. Award criteria parameters could improve consistency and equity, such as a funding cap of "X" dollars per kW of microgrid generation. (The CT program cap is $7,000/kW and $3 million per project.) Apparently, no other state has taken this contribution approach. The text provides an example.

Credit Enhancement. OER could use program funds to buy down the interest rate on a third-party financing to enable a microgrid project to get a loan on acceptable terms. This approach has the potential advantage of conserving program funds and leveraging private investment. It has the disadvantage of potential inconsistency and inequity due to case-by-case, microgrid project- and owner-specific financial criteria and ability to get a loan. Institutions such as the CT Green Bank offer this type of approach to support energy and microgrid projects.

Policy recommendation: OER should use the Eligible Equipment method to simplify program administration and foster consistency and equity in funding awards. Eligible equipment grants should exclude generation, but include energy storage and electrical infrastructure. Reference the CT microgrid program electrical equipment list,[27] but make eligible facility internal rewiring to enable critical load circuit modifications and load shedding. OER should consider also providing applicants with the option to request Capital Contribution and Credit Enhancement awards also, which would be evaluated on an equivalent basis with Eligible Equipment applications (*e.g.*, dollars per project or $/kW of DER capacity). This would provide an incentive to applicants to leverage non-program funds such as private investment, because smaller grant requests would be assessed more favorably.

PART D: MICROGRID PROGRAM AND POLICY RECOMMENDATIONS

Section D1 provides an overview of other states' microgrid programs in CA, CT, MA, NJ and NY. CA, CT and MA programs are broadly similar in structure, with CA funding a smaller number of microgrid projects (7) than CT (11) and MA (21), mostly Level 1 single facility or Level 2 campus microgrids. Each state issued solicitations for grant funding applications for microgrid projects. NJ provided funding for DERs at scores of municipal critical facilities, and its Energy Resilience Bank has a program to fund Level 1 microgrids at wastewater treatment facilities and hospitals.

[27] See list in CT DEEP *Final Round 3 Application Instructions*, Part E-1, pp. 9–10, accessed at: http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/69dc4ebaa1ebe96285257ed70064d53c?OpenDocument

Some states are working on the bigger picture barriers and opportunities surrounding Level 3 multi-user community microgrids. Both the NJ Town Center DER project and the NY Prize program are working to develop pathways to Level 3 multi-user community microgrids. CA is developing a microgrids roadmap. The MA Clean Energy Center (MA CEC) and Boston Redevelopment Authority (BRA) have conducted research and tool development aimed at fostering Level 3 microgrids. Research and policy deliberations underway in Maryland[28] (in particular) and Minnesota[29] (less so) are also grappling with these issues. But only in NY and to a lesser degree MD (and arguably in CA) is this effort occurring in the context of a comprehensive rethinking of traditional utility regulation. See D2.2 for further discussion.

Policy recommendation: Many of the more complex successful microgrids were built in phases, such as the University of California - San Diego campus microgrid.[30] OER should take the same approach and develop microgrid programs and policies in phases.

The first phase is the primary focus of this report: a program aimed at helping public agencies and others conduct feasibility assessments of the potential for Level 1 single facility and Level 2 campus critical facility microgrids, with a competitive solicitation to identify and fund promising projects. OER should model this microgrid program on a hybrid of the CT and MA programs: follow the CT DEEP program structure, plus elements of the MA DOER CCERI program (particularly up-front feasibility assessment support and allowance of Level 1 single-facility microgrids). Complement the solicitation with a top-down effort to focus energy assurance support on uniquely critical assets, including liquid fuels terminals and gas stations. This program can be conducted in successive iterations with public feedback and other quality assurance in between funding "rounds" to facilitate programmatic learning and continuous improvements.

The second phase would evaluate the pros and cons of potential pathways to development of Level 3 multi-user community microgrids. This exploration should only occur in the context of a comprehensive review of energy policy and utility regulation akin to the NY REV process, and although microgrids can be one driver of this discussion, they should not be the primary motive. The RI energy policy community is undertaking numerous innovative and forward-thinking policy deliberations and implementation efforts, many of which share common elements and vision. But in the authors' humble opinion, a comprehensive framework and forum is lacking (although it might be emerging). Community-scale microgrid development could spur that discussion, but should not precede it. See section D2.2 for further discussion.

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[28] See *Maryland Resiliency Through Microgrids Task Force Report* at: http://energy.maryland.gov/documents/MarylandResiliencyThroughMicrogridsTaskForceReport_000.pdf
[29] See *Minnesota Microgrids: Barriers, Opportunities, and Pathways Toward Energy Assurance* at: http://mn.gov/commerce-stat/pdfs/microgrid.pdf
[30] https://building-microgrid.lbl.gov/ucsd

Section D2.1 suggests principles to inform policy goals of program design. The 2015 *Rhode Island Thermal Working Group Report* developed an excellent set of ten principles that are broadly applicable to other energy programs, including microgrids.[31] The following principles of program design are drawn from lessons learned by administrators of similar microgrid programs in other states, as well as other energy programs and general programmatic management best practices. They are somewhat repetitive of the Thermal Working Group principles in places.

- Design the program carefully with a multi-stakeholder team before roll out.
- Employ an integrative design approach with the participation of key stakeholders from inception through implementation.
- Take an all-hazards approach.
- Seek alignment with existing objectives: emergency plans, GHG goals, energy programs, etc. Build on past accomplishments, current programs and efforts underway.
- Prioritize public and community benefits, with a focus on support for local and state public agencies.
- Prioritize protection of vulnerable populations: LMI, medically dependent, elderly, prisoners, etc.
- Deploy program funds cost-effectively by leveraging market forces, private investment and existing programs.
- Educate the marketplace with proactive outreach, template documentation and program transparency.
- Make the program as user-friendly as possible, yet detailed enough to foster successful project design.
- Enable microgrid host/owner an optimum degree of choice and foster market flexibility and creativity in microgrid development.

Section D2.2 addresses the biggest policy decision: What (if any) changes to regulatory regime and role of EDC and/or third party market actors in MG development does OER want to pursue? *The biggest questions relate to potential reshaping of the EDC business model by allowing it to do things it does not or cannot currently do, and/or by allowing non-utility entities to do things that are currently exclusively EDC functions or to compete directly with EDCs for service provision.*

The authors recommend that significant modifications to the regulatory regime should not be undertaken for microgrid program development alone, in isolation from more comprehensive consideration. State-supported microgrids are a means to an end— energy assurance for critical infrastructure mission assurance—and they can support multiple policy objectives simultaneously, but microgrids are not an end in themselves. Minor modifications that require regulatory approval, such as novel tariffs or other case-specific issues of rate design to support Level 1 or Level 2 microgrid development, probably do not constitute much of a challenge to the

[31] See 2015 *Rhode Island Thermal Working Group Report*, pp. 13–14, at: http://www.energy.ri.gov/documents/Efficiency/Rhode_Island_Thermal_Working_Group_Report.pdf

current regulatory regime. In contrast, policies intended to foster development of Level 3 multi-user community microgrids would involve more significant changes to the regulatory regime and the EDC business model that touch on nearly every aspect of energy policy and EPS planning and operations, of which microgrids are but one aspect.

If Rhode Island wishes to revisit and re-imagine fundamental aspects of the EPS and the role of the EDC, the authors recommend that effort should be allowed the time and resources to develop a comprehensive, thoughtful, multi-stakeholder consultative process. A single-issue foray into tinkering with fundamental issues risks undesired unintended consequences. However important or time-sensitive is the need to improve energy assurance and socioeconomic resilience, those imperatives should not push microgrids into being the primary driver of fundamental change to the current regulatory regime.

Many Level 2 and Level 3 microgrids are built in phases; this approach can be applied to microgrid program design as well. An initial phase of strategy development and program definition with an integrative design approach can establish both short- and long-term objectives and measures. Successive iterations of program development can be undertaken with intervals enabling stakeholder feedback, analysis of lessons learned and implementation of program improvements. Each phase’s structure and investments should provide a flexible basis for future development, with an eye towards technological developments and marketplace trends. A program comprising largely administrative measures can be initiated while longer-term, multi-stakeholder discussions and processes are pursued with regards to legislative and regulatory elements.

OER could consider convening a working group with representatives from the PUC, EDC and other stakeholders to assess what microgrid-related actions by the EDC, customers, and/or third party non-utility microgrid developers are allowable and desirable under the current legal and regulatory regime. This working group could then consider what changes (if any) to the current regulatory environment would be desired to foster development of multi-user Level 3 community microgrids.

This section lists microgrid program design options in roughly ascending order of the degree and complexity of change required of the current regulatory environment. It describes factors that hinder development of Level 3 multi-user community microgrids such as actual or perceived regulatory and legal constraints.

Section 2.3 provides recommendations for administrative program measures and actions that OER could undertake under current conditions, including:

Provide program funding to assist with MG development at program & project level. Funding types and sources, program administrative costs, and funding strategies are discussed. As the level of program funding is uncertain, to help conserve resources the following funding priorities are suggested for the Eligible Equipment approach, ranked most to least important:

- Eligible equipment - Electrical infrastructure but not generation or storage (*e.g.*, point of common coupling, wires, controls, switchgear, transformers, communications, protective relays and transfer trips, etc.).
- Feasibility analysis.
- Eligible equipment - Energy storage systems.
- Eligible equipment - Generation and energy storage equipment.

Capital Contribution and Credit Enhancement strategies could complement the Eligible Equipment approach, and could foster applicant use of private investment. See section C2.3 for further discussion.

Develop multi-stakeholder inter-organizational program administration team. Program design and implementation should include a core team comprising representatives from OER, RIEMA, RIGIS, RIIB, PUC/DPUC and National Grid. Critical facility owner/operator and microgrid developer stakeholders could be considered the primary “target market” of the microgrid program, and could provide input to program design but don’t necessarily need to be regular participants in program design. See section 2.3 for a list of suggested stakeholders. OER should consider developing a list of pre-approved contractors, categorized by microgrid-related service offering.

Provide EDC with direct role in program and in MG project planning and development, and require microgrids to coordinate with the EDC on design and operations. Microgrid projects need to coordinate with the EDC for safe management of grid operations, and must be designed to meet interconnection requirements. Key microgrid project and program considerations about respective roles and responsibilities must be clarified with the EDC. OER could consider requiring microgrid project developers to work with the EDC by making an interconnection application a prerequisite for funding applications, or including the EDC in feasibility assessments. A microgrid program could impose a significant burden on EDC staff time, for example by a spurring a surge in energy usage data and interconnection information requests. Preplanning, streamlining and standardizing anticipated microgrid-related processes could reduce costs and uncertainty for both developers and the EDC; see section 2.3 for a list of suggested plans and program options and further details.

Define microgrid and critical facility for program participation and project eligibility to utilize program-related enabling rules and exceptions. One benefit of a programmatic definition is that clearly-defined microgrid project conditions could create a unique space in which special conditions, new rules or exemptions, and experimental administrative/legislative/regulatory measures can apply. This definitional “safe space” could be restricted to those projects that receive program support, or extend to all projects that meet the definition. This approach could reduce programmatic risk by limiting unintended consequences from program-specific measures, and reduce political risk by fostering stakeholder buy-in. See section 2.3 for discussion of issues that would be useful to define or clarify in program eligibility, and recommended actions.

Develop and deploy a robust education program. For most RI energy marketplace participants and facility owners, microgrid design and operational configurations are relatively new concepts and involve unfamiliar combinations of both existing and newer technologies and business models. A microgrid support program itself will be new to all involved, and can be thought of as being somewhat "ahead of the marketplace." Program elements should include a website with posted FAQs, public presentations and "meet and greet" meetings to match projects with goods and services providers.

Use project planning guides, and a detailed RFP / application that defines technical and economic requirements. This should include project planning guides and reference material, RFP-type funding application forms, and business model templates.

Consider a two-tier process to provide high-level screen of feasibility analysis. This could benefit potential microgrid developers and critical facility owners by enabling them to develop a pre-screening process involving high-level estimates and a minimum of effort, so that OER can let projects know whether they "made the cut" to proceed to a higher level of feasibility analysis. If OER provides robust up-front feasibility analysis support, this separate step might not be necessary.

Provide funding support for feasibility analysis. If sufficient program funding is available, OER should provide up-front funding, and ideally contracted technical support teams, to assist project developers with feasibility analysis. Such funding increases program size and cost but is likely to provide better results. RIGIS can provide mapping information conducive to microgrid development, such as locations of proximal critical facilities.

Prioritize energy efficiency and clean energy. Load reduction via energy efficiency is generally cheaper and cleaner than onsite generation. Projects should be required to conduct detailed energy audits and invest in load reduction before sizing and installing onsite generation. OER should favor renewable and clean(er) energy sources such as PV, wind and CHP for microgrid projects, to align with other policy goals. OER should consider the program and project role of existing and new fossil-fueled generators. See section 2.3 for discussion of program features.

Employ rolling application deadlines and/or allow several months for feasibility analysis and application development, especially for municipalities. The program could provide sufficiently long RFP development periods or rolling deadlines (perhaps with a backstop period of 12–24 months) to facilitate participation by public sector organizations with often-prolonged processes for decision making, procurement and energy/facility capital improvement project development. Planning and scheduling should also consider the time it will take for administrative processes, and alignment with DER program deadlines such as REG program open access periods.

Employ design and construction schedules with ample time and administrative flexibility. It is important to provide sufficient time and flexibility with awardee project development schedules to allow for protracted municipal procurement processes, marketplace learning, and common design and construction schedule slippage. Microgrid project novelty and complexity are drivers of project delay. In both CT and MA only a minority of funding recipients remain on schedule and most are not yet operating as of early 2017, even many months after funding awards. The microgrid program team should be as flexible and reasonable as possible; should expect delays; and should be willing to grant extensions of six months of more.

Application review, selection process & criteria. A competitive solicitation RFP should establish criteria for selection including prerequisites such as minimum performance requirements, and request information about project technical and financial characteristics. OER and its program team would evaluate applications involve a scoring process. The recommended approach is a streamlined Point Scoring system to reflect non-traditional "macroeconomic" factors. Significant feasibility analysis support should be provided if a detailed Economic Evaluation approach is taken. See section C1 for further discussion.

Provide streamlined or preferential administrative and permitting processes. Administrative and permitting documentation and processing times for common islandable-DER-related technologies could be standardized and streamlined in cases as a part of program design. Priority could also be given to microgrid projects for certain administrative processes such as siting and permitting, *e.g.*, by enabling applicant projects to move to the head of the queue. Microgrid planning guides could facilitate project development. Modifications to permitting processes must be undertaken with care, to allow that critical public interests (*e.g.*, environment, land use, justice) that are vetted in a permitting process must remain a priority. Examples could include interconnection applications, REG program installation configurations for grid-independent operation, and DER (*e.g.*, battery energy storage systems) siting and permitting prioritization.

Consider award disbursements based on milestones. Provide initial disbursements of award funds with further disbursements tied to project milestones, *e.g.*, 1/3 of an award could be provided upon award with 2/3 provided upon project completion. Up-front funding disbursements of a portion of the funding upon award will help municipalities and their contractors with project development. Final disbursements should come only after thorough commissioning and islanding testing of a microgrid installation.

Commissioning must be complete to receive full funding. Commissioning (Cx) of microgrid installations is vital and should include full-load functionality testing of all major microgrid systems at every stage of operation: from grid-parallel, through disconnection or islanding from the EPS, grid-independent island mode, and reconnection to the EPS.

Require performance evaluation and data monitoring and collection annually or in real time for contract term. Funded or designated microgrids should be required to meet specified performance metrics, and to provide annual reporting or real-time data access.[32] A minimum requirement would be compliance with IEEE 1547.4.

[32] For further discussion with examples see CEG/RPP, *What States Should Do*, June 2015, p.24.

Section 2.4 provides recommendations for legislative measures and actions that could support microgrid development, including:

Expand DG / DER program support. Rhode Island has a number of programs and incentives that support DG and DER development. These could be enhanced to facilitate microgrid development, and in cases could apply only to islandable DERs in a microgrid configuration. See section 2.4 for further discussion of relevant programs and recommended actions, including a feed-in tariff for islandable DERs; RECs or other production-based revenue for CHP power and/or thermal output; expanded net metering; Virtual Net Metering (VNM) for an expanded set of eligible generation, beneficial accounts and multiple customer classes; and expanded community aggregation options.

Include microgrids in RES or as a stand-alone mandate, with incentives.

Enable approved microgrids to distribute power across public ROW and utility easements. Legislation that explicitly allows critical facility microgrid developers to distributed power across a public right of way or a utility easement would address a significant barrier to development of Level 2 campus-type microgrids. As with other proposed exceptions to the current regulatory context, it could make sense to limit this ability to projects that meet a narrow definition of a designated municipal or public purpose microgrid. The Mass CEC helped fund a study by Harvard Law School of the issue that concluded that there was no statutory barrier to municipalities distributing power across a ROW.[33] OER should undertake a similar review of RI law.

Create enabling structures to facilitate economical and legal and low-risk project development behind the meter (BTM). The state could consider legislation enabling special purpose entities or modifications to existing programs to create or expand financing and procurement options for microgrid development by public agencies in particular. Potential approaches include Energy Improvement Districts or similar structures, and expanding RIIB C-PACE program scope for defined microgrids.

Section 2.5 provides recommendations for regulatory measures and potential PUC actions that could support microgrid development. Please note the authors' cautionary comments in section 2.2 regarding making potential fundamental changes to the regulatory regime for the primary motive of microgrid policy. See this section for discussion of aspects of marketplace regulatory structure to consider in enabling Level 3 microgrids, and of current and recent PUC actions and dockets that relate to microgrid development.

Inducing changes in EDC behavior can be accomplished via mandates and/or incentives such as performance-based regulations. Requirements can convey greater certainty of achieving desired outcomes, yet risk high costs, unintended consequences and stakeholder (*e.g.*, EDC) alienation. Effective incentives can help align commercial interests and investment with public policy

[33] http://environment.law.harvard.edu/wp-content/uploads/2015/08/masschusetts-microgrids_overcoming-legal-obstacles.pdf

objectives and promote least-cost achievement of desired results. A detailed exploration of the issues, risks and trade-offs around mandate or incentive design for the EDC in Rhode Island is beyond the scope of this report. Potential regulatory measures include:

Require, incent or enable the EDC to provide information on potential locations for microgrid development of greatest value to the EPS. The PUC could require or incent the EDC to provide information about the costs and benefits to the EPS at the distribution and potentially transmission levels, to inform microgrid planning. This information could be made available solely to the OER microgrid team to inform evaluations of funding applications. Alternately or additionally, this information could be made available to the marketplace in at least a generalized level of detail, either upon request at a project-specific level or in the form of publicly-identified areas that would benefit the most from microgrids, akin to the "opportunity zones" identified by NYSERDA for the NY Prize competition.

Require, incent or enable the EDC to create custom tariffs for cost recovery and/or rate risk reduction in microgrid locations, and/or for microgrids to monetize sources of value that they provide to the EPS and EDC. A detailed exploration of the issues, risks and trade-offs of these aspects of market re-design in Rhode Island is beyond the scope of this report. Microgrids and their DERs provide benefits to the EPS as well as impose costs and their full net value should be compensated, just as the costs they impose on the system should be recovered. It would be important that the services sold in each direction are identified, evaluated and priced in a consistent, fair and transparent way.

Custom tariffs that are customer- or project-specific enable the EDC to recover costs from those customers who will most directly benefit from a microgrid. This is arguably more equitable than, and preferable to, socializing the costs across all customers statewide by adding them to the EDC's rate base. Please note that there may be some precedent for rate-basing investments in localized EDC improvements in the context of LCP and NWA. The EDC already has at least one option to apply a custom tariff for enhanced reliability, by adding a second feeder for N+1 redundancy. This capability might already enable the EDC to develop reliability enhancement custom tariffs for other types investments, possibly including investments such as hardening or other modifications to distribution infrastructure connected to—or within—a microgrid.

Another potential policy would be to allow the EDC to enter into project-specific long-term fixed-rate contracts (10–25+ years) to reduce tariff variability risk and facilitate microgrid financing.

Require, incent or enable the EDC to procure energy from resilient islandable DERs.

Require, incent or enable the EDC to use on bill financing for microgrid investments.

Require, incent or enable the EDC to own or contract for generation and/or storage, in excess of 15 MW cap. An alternative or possibly complementary approach to "animating the marketplace" could be for the state to expand the ability of the EDC to own or contract for generation and storage, giving the EDC a more direct role in Level 3 multi-user microgrid ownership and development. This approach would entail fundamental alteration of the regulatory regime and is not recommended in the absence of a NY REV-type comprehensive re-examination of the current model. See this section for further discussion and policy options and trade-offs.

Require, incent or enable the EDC to participate in utility-directed and/or hybrid microgrid models. See cautionary discussion in the previous section. In a utility-directed microgrid, the EDC owns and operates the microgrid assets, including generation and storage. In a hybrid microgrid ownership model, the EDC shares ownership of microgrid assets with a third party, *e.g.*, the EDC might own the distribution network and controls while a third party owns the generation. One strategy could be to enable differently-regulated EDC subsidiaries to play a role in microgrid project development.

Exempt microgrids from PUC regulation that are publicly-owned or below a size cap. See this section for further discussion of potential PUC requirements for designated exempt classes of microgrids.

Enable non-utility third parties to own and operate Level 3 multi-user microgrids. Enabling third parties to compete with the EDC in providing energy services and owning and operating microgrid DERs and distribution infrastructure could constitute the greatest change to the regulatory regime. A variation on this approach could involve pathways to municipalization or cooperative ownership models.

INTRODUCTION

1. What is the problem?

There is bad news and good news.

The bad news is that United States faces a critical national vulnerability: over-reliance on an Electric Power System (EPS) or "grid" that serves us very well under normal conditions but is vulnerable to prolonged disruptions from a range of natural and man-made hazards, despite the historical best practices of regulated utilities. Long duration outages lasting more than one week—and potentially months—are rare, but outage frequency and duration are increasing and the risks of severe disruptions are growing. Worst case plausible scenarios could devastate the economy and harm or kill Americans in numbers not seen since the Civil War. National planning and action to reduce these risks is thus far insufficient to the scale of the problem, and evidently national preparedness for this type of emergency is lacking.[34] A large burden of preparedness falls on state and local shoulders.

The good news is that solutions are available to reduce these risks and provide other benefits as well. Distributed Energy Resources (DERs) such as combined heat and power, solar energy, wind power, energy storage and energy efficiency can deliver energy services at lower cost, risk and pollution than can the grid alone. Growing deployment of these solutions is increasingly economical due to technological innovation and state-level energy policies. Microgrids can integrate DERs with controls and switchgear to enable both grid-connected and grid-independent operations to energize society's critical infrastructure when the power is out, and provide other benefits that help maximize DERs' value. State level policies and programs can accelerate deployment of these technologies by addressing barriers in the marketplace and the current legal and regulatory environment.

Several states have undertaken research and funding efforts to support microgrid development, including California, Connecticut, Maryland, Massachusetts, New Jersey and New York. Rhode Island is considering development of a similar program.

This report is the deliverable for a consulting contract with the Rhode Island Office of Energy Resources (OER), as requested in solicitation #754979 *Resilient Microgrids for Critical Services*. In the wake of Superstorm Sandy's multi-day power outages and other severe weather events in recent years, OER sought consultant support for design of a program intended to

[34] The authors recommend journalist Ted Koppel's 2015 book *Lights Out: A Cyberattack, A Nation Unprepared, Surviving the Aftermath* for an accessible description of these risks and the apparent lack of coherent planning and shared risk assessment among recent leadership of the Federal Emergency Management Agency and the Department of Homeland Security.

enhance the energy assurance of critical infrastructure through deployment of distributed energy resources and other means. This effort draws from lessons learned in other states with similar programs.

This report discusses microgrid types, technologies and applications, as well as potential state-directed program design and policies. It is written for OER staff and assumes familiarity with RI energy systems and laws, although the authors attempt to make the content accessible to less specialized readers with brief explanations and a glossary. The authors reference and quote at length from state microgrid reports and other sources, making use of excellent work by others rather than repeating the task. For the sake of brevity this report provides a brief overview of each subject, and suggests resources for further reading.

1.1 Critical facilities are dependent on vulnerable critical infrastructure

Our modern society and economy rely on interdependent "systems of systems" of critical infrastructure. The EPS is arguably the most fundamental of these, in that so many other critical systems rely upon it to sustain functionality.

The EPS is a modern miracle, the largest and most complex machine ever built. EPS operators must balance electric power supply and demand in real time to maintain voltage stability and alternating current frequency within relatively narrow parameters, a dynamic process involving thousands of generators and millions of customers. Failure and disruptions can cause the system to collapse at local or regional scales. Given these challenges, it is remarkable that there are not more blackouts. "The reliability of the electricity system is measured by the percentage of time per year an average customer can expect to have service. The US power system is typically reliable 99.9–99.99% of the time, [which] equates to approximately 1–9 hours per year without power for the average customer."[35]

The EPS is vulnerable to outages, most of which originate in the lower-voltage distribution network.[36] Most outages are brief, even momentary, and electric utilities dedicate significant effort into planning and preparation for prompt restoration of services. The 1965 Northeast regional outage spurred the creation of the North American Electric Reliability Corporation (NERC), a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system by developing and enforcing reliability standards.[37] Cascading regional outages in 1977 and 2003 led the Independent Systems Operator-New England (ISO-NE) to monitor remote disturbances in other regional transmission operators (RTOs) and can automatically protectively isolate our region. Yet many observers believe that the risks of prolonged large-scale outages are growing due to both natural and man-made causes.

Power outage impacts ripple through interdependent systems of critical infrastructure and the metabolic processes of our modern industrial economy. During large scale disasters, emergency

[35] NYSERDA 2010, p. 92.
[36] RIEAP, p. 6-17.
[37] http://www.nerc.com/AboutNERC/Pages/default.aspx

response and EPS service restoration rely heavily on mutual aid from outside the affected area; the greater the scope and duration of the blackout, the worse the impacts. No power means no water, fuel, food, communications, mass transit, first responders, health care, sewerage treatment, or heating and cooling buildings once backup generator fuel supplies are exhausted. Decades of effort to wring inventory from corporate supply chains in favor of "just in time delivery" have rendered us more vulnerable to disruptions. The Northeast region is heavily dependent on long-distance trucking for food supply and maintains a single digit number of days of edible inventory in local storage.

In general, owners and operators of critical infrastructure are responsible for Continuity of Operations (COO) or mission assurance during disruptions such as power outages. Federal agencies provide some support for critical infrastructure protection (particularly in cyber defenses). A large burden of responsibility for emergency preparedness and energy assurance falls on local shoulders, where resources are often constrained. In most localities, there is no one "owner" of energy assurance and resilience missions; the Chief Resilience Officer position is a relatively new staffing development.

The most common form of energy assurance is a standby fossil fueled backup generator (BUG), which typically run on diesel. Most BUG owners do not store more than 72 hours of fuel onsite. Regional disruptions such as storms can interrupt power for longer periods and interfere with the liquid fuels supply chain. A minority of BUGs are duel-fuel or use natural gas, with greater security of supply due to diversification or pipeline resilience. BUGs are usually standby assets and poor testing and maintenance procedures can contribute to poor availability factors when needed.

Facility owners also can install constant-duty DERs such as combined heat and power (CHP or cogeneration) or solar photovoltaics (PV) plus battery storage to serve their critical loads and enhance their energy assurance, if only by conserving diesel supply by reducing BUG run hours. These DERs can also convey economic benefits during typical "blue sky" daily operations.

1.2 Risk trade-offs of centralized *vs.* distributed EPS models

In part the vulnerability of the EPS to disruptions is an unintended consequence of the historical business model of large, remote power generation stations connected to distant customers by higher-voltage transmission and lower-voltage distribution networks. Fewer, larger power generators enable power producers to leverage economies of scale in the production of low-cost power. But thousands of miles of overhead wires are exposed to risks ranging from severe weather to accidents and even attack.

More recent technological advances in DERs are reshaping the economics of power generation and the potential configurations of the EPS. Smaller distributed generation (DG) located close to the end-user enable producers to leverage economies of scale in the production of low-cost power generation capacity, and avoid line losses associated with long-distance transmission. Many DERs offer provide lower emissions and are based on renewable resources. Regulators have created policies intended to foster deployment of DERs such as net metering. Policy innovations have expanded development of new valuation models that incorporate a broader set of DER costs and benefits into EPS planning. Smaller-scale generation now comprises the largest share of marginal additions of generation capacity to the EPS.

The traditional EPS model of fewer large units of centralized generation capacity connected to remote customers is inherently more vulnerable to disruption than an emerging, more distributed model of many small units of distributed generation located at or close to customers. The centralized model is subject to the loss of larger blocks of generation capacity with fewer points of failure. The distributed model reduces reliance on wires, line losses, and the risk of transmission and distribution disruptions (*e.g.*, tree impacts, geomagnetic currents induced by electromagnetic pulse or solar flares—see Appendix A for further discussion).

On the other hand, the distributed model introduces challenges to EPS control and balancing supply and demand, most of which have effective management strategies. Growing numbers of customer-directed DG units are being added to an EPS constructed to manage mostly one-way flows of power from central generation to customers. In many cases the DG can feed power onto the distribution system, with potentially rapid swings in output from intermittent resources such as PV and wind turbines. This can result in unanticipated and uncoordinated surges and sags in power supply and demand on distribution circuits at the local level, which can increase outage risks. There is debate over the ability of the EPS to handle high levels of renewable energy penetration, yet generally management techniques have proven successful to date, even in cases where RE penetration exceeded 20% of local EPS generation capacity. Centralized EPS control can be improved with more complex sensors, relays, communications and other equipment often bundled under the "smart grid" concept.

Microgrids reflect the epitome of the distributed EPS model, and convey their own risk tradeoffs. Microgrids can reduce customers' risk of disruptions by enhancing the ability of connected facilities to have power during EPS disruptions. However, this reliability should be assessed in the context of the microgrid being connected to the EPS. Although microgrids can greatly increase the probability that power will be available during outages, in most cases the EPS provides more reliable service on a day-to-day basis. Microgrids are complex and have fewer resources and less redundancy to maintain operation than does the vastly larger EPS. A grid-connected microgrid benefits from EPS reliability to back up its own onsite DERs, which often are not as reliable as the grid. Yet a microgrid can have a good probability of being operational during any given EPS disruption.

Microgrids can have mixed impact on DER risks to the EPS. Features that can help reduce risks include the microgrid's ability to manage DERs directly, and microgrids can be designed to accommodate high levels of renewable energy generation. Microgrids can represent relatively large blocks of load that can rapidly be removed from or added to the EPS, risking EPS instability unless there is coordination between grid and microgrid operators. Coordination between EPS and microgrid operators can reduce risks to the EPS (and add significant value) by dispatching microgrid DERs to either shed load or contribute generation to help stabilize the grid when needed.

1.3 Risks to the Rhode Island EPS

The Rhode Island Energy Assurance Plan (RIEAP) cites six priority hazards listed in the Rhode Island Hazard Mitigation Plan (RIHMP), noting: "The hazards that are considered to be of greatest consequence are hazards associated with extreme weather events, specifically hurricanes and winter snow storms."[38]

- Flood-related
- Wind-related
- Winter-related
- Drought
- Flash floods
- Geologic-related

The 2014 RIHMP update added wildfires and extreme heat to the hazard list; see Figure Intro-1 below.

Figure Intro-1: RIHMP 2014 Hazards[39]

Rhode Island Hazard Mitigation Plan
2014 Update

Wind Related Hazards	Winter Related Hazards	Flood Related Hazards	Geologic Related Hazards	Additional Hazards
Storm Surge	Snow	Riverine Flooding	Earthquakes	Wildfire
Hurricanes	Ice	Flash Flooding		Drought
Tornadoes	Extreme Cold	Urban Flooding		Extreme Heat
High Winds		Coastal Flooding		
		Climate Change and SLR		
		Coastal Erosion		
		Dam Breach		

Wildfire and extreme heat were added to the vulnerability assessment for the 2014 plan update.

RIEAP surveyed electricity and petroleum industry stakeholders, who identified natural disasters as the biggest threat to their energy supplies, while natural gas stakeholders described a transmission pipeline disruption as the biggest threat to their energy supply.[40]

The RIEAP uses RIHMP hazard classifications, with three main categories: Natural (*e.g.*, extreme weather, epidemics, wildfires), Technological (*e.g.*, equipment failures), and Human

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[38] RIEMA, *Rhode Island State Hazard Mitigation Plan*, 2011, cited in RIEAP, p. 9-4.
[39] RIEMA, *Rhode Island 2014 Hazard Mitigation Plan Update*, 2014, p. 35. Accessed at: http://www.riema.ri.gov/resources/emergencymanager/mitigation/documents/RI%20HMP_2014_FINAL.pdf
[40] RIEAP, pp. 3-2 & 3-3.

(*e.g.*, intentional harm or human error accidents). The authors group hazards into natural and man-made categories, but reference the RIHMP classifications.
Hazards that pose risks of long duration power outages (defined here as lasting longer than 3 days) are listed below. Appendix A describes these hazards in more detail, and suggests potential policy responses. These are acute hazards (although pandemics would develop over longer periods). Climate change is a slowly occurring hazard, but can be considered a "force multiplier" capable of amplifying natural hazards. (Anthropogenic or human-influenced climate change could be described as a "man-made natural hazard".)

Hazards listed in **bold font** are "High-Impact, Low-Frequency (HILF) Events" or "Black Sky Hazards" that can cause very long duration outages (defined here as lasting longer than one week). Events that damage or destroy critical infrastructure with long replacement times can disable energy networks for weeks to months. Central power stations, high voltage transformers and other complex and often custom-built equipment have limited spares or options for replacement, and key components are often made overseas. Some Black Sky events can have regional or national effects with potentially catastrophic impacts. Electromagnetic hazards or "E-Threats," caused by solar flares or the electromagnetic pulse (EMP) created by a high-altitude nuclear explosion, pose risks of multi-region or even national-scale prolonged outages.

<u>Natural hazards</u>

- Weather – Wind: Tree fall, blown debris, **severe storms**
- Weather – Wind: Storm surge, seawater inundation
- Weather – Precipitation: Rain, freshwater inundation
- Weather – Precipitation: Snow, **ice**
- Weather – High heat, drought, wildfires
- Geologic/Seismic – Earthquake, **tsunami,** volcano
- **Space weather – Solar flare / coronal mass ejection (CME) / geomagnetic disturbance (GMD)**
- Pandemic

<u>Manmade hazards</u>

- Aging infrastructure, equipment failure
- Human error, accidents
- **Physical attack**
- **Cyberattack**
- **Intentional Electromagnetic Interference (IEMI) attack**
- **Nuclear weapons – Electromagnetic Pulse (EMP) attack**
- Nuclear weapons – **War,** terrorism, dirty bombs

1.4 National Grid hazard response and historical reliability

These issues are discussed in more detail in Appendix B.

National Grid is the electricity distribution company (EDC) serving ~99% of RI customers.[41] The RIEAP states: "National Grid's system contains a considerable amount of redundancy and system protection to minimize the impact of events to its customers…. National Grid's electric system is reported to be designed to withstand the loss of any single high voltage element (*e.g.*, transmission lines, transformers or power plants) without any impact to customers, which is compliant with NERC standards."[42] National Grid also is the state's only natural gas Local Distribution Company (LDC) and maintains redundant pipeline and storage capacity for system reliability and resilience, including for RI's power generation which is almost entirely dependent on natural gas supply.[43]

Despite best practices, any EDC is vulnerable to hazards that can cause prolonged outages. Severe weather events and other natural and man-made disasters pose challenges that are almost impossible for grid operators to overcome.

National Grid reports annually on its reliability using industry-standard metrics including System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Major Event Days (MEDs) that exceed a threshold value SAIDI. (See Appendix B for definitions and further discussion.) Both SAIDI and SAIFI are calculated with and without the inclusion of MEDs.

The impact of longer-duration blackouts is notable in a comparison of outage metrics both with and without MEDs. A review of SAIDI, SAIFI, and outage causes from 2011–2013 (years with several severe weather events) illustrates the impact of MEDs. We considered only customer interruptions attributed to trees, transmission, sub-transmission and substation causes, as a very approximate correlation of outages with typical severe weather impacts on EPS overhead infrastructure (*e.g.*, wind-felled trees and blown debris that damage wires). Including MEDs increased total customer interruptions by 164% in 2011, 64% in 2012, and 161% in 2013, totaling an additional 620,275 interruptions.

This general high-level comparison is at best a very rough indicator of correlation, without sufficient detail to establish causation between the named storm events and interruption data.

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[41] From National Grid, *Electric Infrastructure, Safety and Reliability (ISR) Plan FY2017 Proposal*, p.26: "[National Grid] delivers electricity to 486,465 Rhode Island customers in a service area that encompasses approximately 1,076 square miles in 38 … cities and towns. To provide this service, the Company owns and maintains 5,225 miles of overhead and 1,103 miles of underground distribution and sub-transmission circuit in a network that includes 94 sub-transmission lines and 390 distribution feeders. The Company relies on 66 distribution substations that house 134 power transformers and 823 substation circuit breakers to deliver power to its customers. The Company's electric delivery assets also include 280,612 distribution poles, 4,252 manholes, and 77,540 overhead (pole-mounted) and underground (pad-mounted or in vault) transformers."

[42] RIEAP, p.9-8.

[43] RIEAP, p. ES-7.

Nevertheless, this data suggests that microgrids can significantly benefit customers during longer outages. MEDs impose the greatest challenges to critical facilities and the communities that depend on them, especially multi-day outages; these contingencies are where microgrids can provide the greatest value. Critical facility microgrids are generally less susceptible to severe weather disruptions than is the EPS, if only due to reduced reliance on vulnerable transmission and distribution networks. Microgrids comprising small numbers of critical facilities could not much reduce the numbers of customer interruptions, but they could significantly reduce suffering and improve public health and safety for large numbers of customers by maintaining critical services and safe havens during prolonged outages.

2. <u>What is the solution?</u>

Addressing the risks of severe disruptions to the EPS requires the engagement of stakeholders at all levels. Arguably this issue is where national security is most tangibly a local concern, and an imperative for both centralized and decentralized responses. Centralized solutions such as the policies and activities of Federal agencies, EPS regulators and operators are vital, yet insufficient to address these risks comprehensively, particularly at the local level.

The ISO-NE and EDC both dedicate significant resources to EPS redundant capacity, service restoration, and risk mitigation (*e.g.*, vegetation management, physical and cyber security). But however good any ISO or EDC is at maintaining systemic resilience, energy supply networks remain at risk to the hazards described above that can cause MEDs and black sky events. Infrastructure hardening measures such as undergrounding wires or flood-proofing substations are expensive, and the potential scope is extensive to achieve broad-based risk reduction. Many “Smart Grid” investments such as advanced metering infrastructure distribution network sensors, sectionalizers, breakers, reclosers and protective relays improve outage management and response as well as provide other economic and environmental benefits. Yet regional-scale insults to the system can overwhelm the best-managed grid.

These factors indicate that critical facility owners and operators should consider investing in enhanced energy assurance for Continuity of Operations Planning (COOP). Distributed energy resources can provide facility owners with “blue sky” operational benefits as well as “black sky” mission assurance. Many DERs are cost-effective and eligible for existing policy and financial support, reducing their cost. A state-directed grant or loan program can help facility owners in cases where formation of a microgrid could provide improved energy assurance, but requires equipment that does not provide sufficient cost savings to help recover initial costs over an acceptable period.

Microgrids and their DERs can contribute to achieving multiple goals including:

- Least cost procurement of electricity service delivery and EPS operation (*e.g.*, by shedding load, contributing power, or helping defer transmission and distribution system upgrades)
- Reduced facility operating costs

- Enhanced public health and safety
- Protection of vulnerable populations
- Community economic development and resiliency
- Increased deployment of cleaner energy resources
- Energy-related emissions reductions
- Climate change risk mitigation (*e.g.*, via greenhouse gas emissions reduction)
- Climate change risk adaptation (*e.g.*, via critical facility mission assurance)

This report describes technologies, procurement strategies, and polices that can contribute to microgrid development.

3. <u>How to read this report</u>

This report provides a brief overview of each subject, and suggests resources for further reading.

Part A: Rhode Island Critical Infrastructure describes critical facility criteria, including both Rhode Island EMA's current program and categories as well as examples from other states' programs.

Part B: Microgrid Technologies and Applications provides an overview of common microgrid technologies, their respective pros and cons and economic considerations.

Part C: Cost/Benefit Analysis of Rhode Island Critical Infrastructure Microgrids provides a representative cost/benefit analysis model for microgrid planning and proposal assessment.

Part D: Microgrid Program and Policy Recommendations discusses the characteristics and lessons learned from microgrid support programs in other states, and potential principles and policies for Rhode Island to consider in formation of its own program.

Part E: Microgrid Pilot Program Case Studies describes conceptual design and feasibility assessment, conceptual design and cost/benefit analysis for two low to moderate income multifamily housing buildings in different Rhode Island municipalities, using the methodology developed in Part C.

Appendixes, *Glossary* and *Bibliography* provide reference material.

PART A: RHODE ISLAND CRITICAL INFRASTRUCTURE

The primary objective of an energy assurance or microgrid program is to enhance the functionality of society's most mission-critical infrastructure and facilities during interruptions of vital energy utilities, particularly electricity, natural gas, and other fuels. A Rhode Island Office of Energy Resources (OER) microgrid program will need to determine what types of facilities are critical and eligible for program support, and to provide a program definition.

Definitions of microgrid types and configurations are discussed in more detail in Section B3. For the purposes of this Part of the report, a microgrid combines Distributed Energy Resources (DERs) such as onsite power generation with controls and switchgear to enable both grid-connected and grid-independent facility operations. We reference the simplified typology suggested by the New Jersey Board of Public Utilities (NJBPU)[44]:

Microgrid type	DERs	Facilities	Meters	Facility owners
Level 1 single facility	1–2+	1	1	1
Level 2 campus	1–2+	2+	1–2+	1
Level 3 multi-user community	1–2+	2+	2+	2+

1. What is a critical facility?

There are various definitions of "critical facility," from government agencies and state programs, most of which overlap to a large degree. The criteria are somewhat subjective—one can joke that "if asked, everyone thinks their facility is critical"—and typically rooted in common sense.

The authors distinguish critical infrastructure from critical facilities, with acknowledgement that the distinction can be unclear. A critical facility either performs a mission or function that is critical to the community or sector it supports, or it poses significant risks to its community if it is disrupted, damaged or destroyed. The most critical facilities typically either perform public health and safety missions, or pose the greatest threats to public health and safety via catastrophic failure or damage.

Critical facilities rely on critical infrastructure to maintain functionality. Critical infrastructure can consist of critical facilities, yet also it can include installations and equipment that can't be readily separated into discrete facilities. This is most evident in network industries and utilities such as water, wastewater, electricity, natural gas, liquid fuels, and telecommunications that own and operate distribution networks for commodity stocks and flows (*e.g.*, pipes, wires, cables, transmitters, receivers and storage). These networks include specific facilities that are connected to each other and to sources, sinks and end user recipients of each network's commodity (*e.g.*, water, sewerage, electricity, hydrocarbon gases and liquids, electronic signals).

[44] NJBPU, *Microgrid Report*, 2016, p.17.

Critical facilities can be categorized by ownership as being either public sector or private sector. Typically, the public sector is responsible for public health and safety, although companies can play key roles. Companies provide vital services to the community that can be particularly valuable during prolonged power outages.

See Appendix C for a comparison of state microgrid program's critical facility criteria. Most state microgrid programs consider the following facility types to be mission critical:

- Continuity of government functions: Municipal centers, public works
- Public safety: First responders, emergency operations centers, emergency shelters
- Health: Hospitals, clinics, pharmacies, dialysis centers
- Potable water supply, wastewater treatment facilities and networks
- Residential facilities where vulnerable populations can shelter in place: multifamily housing, nursing homes, corrections facilities
- Fuel and energy supply: Gas stations, delivery terminals, storage facilities
- Communications and information technology: Cell phone towers, radio masts, internet servers, data centers
- Transportation: Train and bus stations, airports, maintenance facilities
- Food supplies: Supermarkets
- Access to funds: Banks, ATMs

The Connecticut microgrid program gives state and local officials latitude to define "critical facility":

"Critical Facility: Means any hospital, police station, fire station, water treatment plant, sewage treatment plant, public shelter or correctional facility, any commercial area of a municipality, a municipal center, as identified by the chief elected official of any municipality, or any other facility or area identified by the Department of Energy and Environmental Protection [DEEP] as critical (As defined in Public Act 12-148, §7). In identifying other facilities or areas as critical, DEEP will consider the extent the applicant can demonstrate that the facility is critical and serves a public need. DEEP has identified the following additional facilities as critical: military bases, communications towers, fueling stations, food distribution centers, and mass transit. In addition, DEEP considers as critical facilities those facilities that have some or all of the following characteristics: provide support for national security; act as a command center; act as an emergency shelter; provide access to food, fuel, money, or medication."[45]

1.1 Federal and RIEMA definitions

The Federal government provides "official" reference definitions of critical facility and critical infrastructure.[46] "The U.S. Patriot Act of 2001 defined critical infrastructure as those 'systems

[45] FINAL Round 3 APPLICATION instructions.pdf, p. 16, accessed at: http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/69dc4ebaa1ebe96285257ed70064d53c?OpenDocument

[46] Consider the Canadian definition: "Critical infrastructure refers to processes, systems, facilities, technologies, networks, assets and services essential to the health, safety, security or economic well-being of Canadians and the

and assets, whether physical or virtual, so vital to the United States that the incapacity or destruction of such systems and assets would have a debilitating impact on security, national economic security, national public health or safety, or any combination of those matters.'"[47]

Presidential Policy Directive 21 (PPD-21): *Critical Infrastructure Security and Resilience*[48] mandated an update to the National Infrastructure Protection Plan (NIPP).[49] This 2013 revision of the plan established 16 critical infrastructure sectors, utilized by the U.S. Department of Homeland Security (USDHS).[50]

The Federal Emergency Management Agency (FEMA)'s Community Rating System (CRS), developed for floodplain risk management, provides the following definition of "critical facility":

"*Critical Facility*: A structure or other improvement that, because of its function, size, service area, or uniqueness, has the potential to cause serious bodily harm, extensive property damage, or disruption of vital socioeconomic activities if it is destroyed or damaged or if its functionality is impaired. Critical facilities include health and safety facilities, utilities, government facilities and hazardous materials facilities. For the purposes of a local regulation, a community may also use the International Codes' definition for Category III and IV buildings."[51]

The Rhode Island Emergency Management Agency (RIEMA) has developed a comprehensive Rhode Island Critical Infrastructure Program Plan (RICIPP) based on the USDHS criteria and classifications. The plan's Vision Statement is: "A resilient infrastructure supporting the delivery of essential services vital to the health & safety, security, and economic prosperity of all Rhode Islanders." The Mission Statement is: "Leading Rhode Island's effort to protect critical infrastructure from all hazards by identifying and managing physical/cyber risks and enhancing resilience through collaboration within the public and private sector critical infrastructure communities." This document complies with the requirements of the Comprehensive Emergency Management Plan [CEMP], previously known as the State Emergency Operations Plan (EOP)…. The critical infrastructure and key resources identified through this program will be utilized by the CEMP to help *prioritize mitigation, preparedness, response, and recovery efforts of the State*."[52] (*Emphasis added*.)

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effective functioning of government. Critical infrastructure can be stand-alone or interconnected and interdependent within and across provinces, territories and national borders. Disruptions of critical infrastructure could result in catastrophic loss of life, adverse economic effects and significant harm to public confidence." Accessed at: www.publicsafety.gc.ca/cnt/ntnl-scrt/crtcl-nfrstrctr/index-en.aspx

[47] The Patriot Act of 2001, Section 1016(e), Critical Infrastructures Defined, http://www.selectagents.gov/resources/USApatriotAct.pdf, Accessed April 14, 2014.

[48] https://www.whitehouse.gov/the-press-office/2013/02/12/presidential-policy-directive-critical-infrastructure-security-and-resil

[49] www.dhs.gov/sites/default/files/publications/NIPP%202013_Partnering%20for%20Critical%20Infrastructure%20Security%20and%20Resilience_508_0.pdf

[50] https://www.dhs.gov/critical-infrastructure-sectors

[51] www.fema.gov/critical-facility

[52] John McCoy, RIEMA, personal communications, Sep. 12th, 2016.

RIEMA modeled its definition of critical infrastructure and Key Resources (CIKR) on the Patriot Act terminology:[53]

> "Critical infrastructure includes those assets, systems, networks, and functions—physical or virtual—so vital to Rhode Island that their incapacitation or destruction would have a debilitating impact on security, economic security, public health or safety, or any combination of those matters."

The National Infrastructure Advisory Council (NIAC) prioritized four highly critical sectors (Energy, Water/Wastewater, Transportation and Communications) with Defining Features of a Lifeline Sector:

- Provides essential products and services that underpin the continued operation of nearly every business sector, community, and government agency.
- Typically delivers products and services that are ubiquitous in normal circumstances but can create life-threatening conditions if they are unavailable for long or even short periods of time.
- Encompasses complex physical and cyber networks that are highly interconnected within their sector, between sectors, and within and between adjacent regions.
- Its disruption or destruction can cause failures that cascade across dependent infrastructures and regions, producing a multiplier effect of impacts.[54]

RIEMA added two sectors (Emergency Services and Information Technology) to the four designated by NIAC, for a total of six Life Line Sectors out of the sixteen CIKR sectors; see Figure A-2.[55]

Figure A-2: Rhode Island Critical Infrastructure and Key Resource sectors

Image courtesy John McCoy, RIEMA.

RIEMA has convened a multi-stakeholder process to develop Sector-Specific Plans (SSPs) that "bring together the efforts of all levels of government, private sector and non-governmental

[53] John McCoy, RIEMA, personal communications, Feb. 2nd, 2016.
[54] John McCoy, RIEMA, personal communications, Sep. 12th, 2016.
[55] John McCoy, RIEMA, personal communications, Mar. 2nd, 2017.

organizations. Together they provide the mechanism for identifying critical assets, systems, interdependencies and functions; understanding threats; assessing vulnerabilities and consequences; *prioritizing protection initiatives*; and enhancing information sharing efforts and applying protective measures within and across sectors…. It is imperative that we understand our entire system of critical infrastructure so we aren't surprised by unanticipated inter-dependencies when a catastrophic event impacts assets critical to Rhode Island."[56] (*Emphasis added*.)

Each sector has a designated Sector Lead Agency (SLA) that "will be responsible for pursuing efforts to enhance the security and resiliency of the State's CIKR by providing the information required to understand security needs, identify vulnerabilities, and to craft cogent, executable SSPs that are trained and exercised…. The purpose of the sector-specific meetings was to create a collaborative venue for CIKR sector partners, both public and private, to create a state-wide sector-specific plan that will establish a profile and goals for the sector; identify critical assets, systems and networks within the sector; assess risks to the sector; *prioritize infrastructure within the sector*; develop and implement protective programs and resiliency strategies for the sector; and measure the effectiveness of those efforts within the sector. Those 16 sector-specific plans will be appended as annexes to the RICIPP, once completed."[57] (*Emphasis added*.)

A database of critical facilities is under development, including stakeholder working group input from each of the 16 sectors to help identify critical facilities. This database includes some parameters for classification and ranking of sites, for example including six high-priority "Life Line sectors" and a mix of public, private and institutional facilities.

As part of the State Facility Safety and Security Initiative, RIEMA developed the Critical Infrastructure Assessment Tool (CIAT), a survey that has been completed 18 State- or quasi-state and 2 commercial facilities as of March 2017; by that time 59 State- or quasi-state and 5 commercial facilities had completed either the CIAT, the DHS Rapid Survey Tool (RST) or the Infrastructure Survey Tool (IST).[58] The CIAT gathers information valuable for energy assurance and for identifying dependencies on specific critical infrastructure. CIAT asks a facility to identify:

- Their electricity service provider as well as primary and secondary/alternate substations
- Whether it has a backup generator (BUG) capable of running mission critical services for 72 hours
- Whether a backup generator assessment been conducted by either FEMA or the U.S. Army Corps of Engineers' Emergency Power Facility Assessment Tool (EPFAT) Program[59]
- Whether it is dependent on natural gas, and if so identify the provider, primary and secondary/alternate sources, and whether the delivery mechanism is via pipeline or truck

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[56] John McCoy, RIEMA, personal communications, Sep. 12th, 2016.
[57] John McCoy, RIEMA, personal communications, Sep. 12th, 2016.
[58] John McCoy, RIEMA, personal communications, Mar. 22nd, 2017.
[59] RIEMA has collaborated with FEMA and US Army Corps of Engineers (ACE) on EPFAT assessments. However, this information becomes restricted after collection, which limits access to FEMA and ACE and thus reduces its value to OER for microgrid planning.

As of early 2016 some 200 critical facilities with BUGs had been identified.[60] CIAT does not currently collect information about facility critical loads, energy systems and use, BUG characteristics such as size or fuel type, or presence of additional onsite distributed energy resources (*e.g.*, solar photovoltaics or combined heat and power systems).

The survey also seeks to identify dependence on water and wastewater systems, communications and transport networks. This information is very useful for identifying key nodes of interdependency and highly critical infrastructure upon which critical facilities are dependent to a significant degree. CIAT request information on additional factors that can inform prioritization, *e.g.*, the numbers of people in the surrounding area at risk of harm or mass evacuation in a worst-case scenario, asset replacement value and business interruption cost.

RIEMA is developing prioritization criteria based on CIAT surveys, ranking facilities by a scored evaluation of factors including facility dependence on critical infrastructure; resilience as indicated by redundancies in critical infrastructure upon which the facility depends (*e.g.*, primary and secondary substation options); and the consequences of a disruption, including exposure risks to designated numbers of people.[61] RI is working on prioritizing State facilities via a DHS Facility Security Level (FSL) ranking, which is being modified to address RI specific needs. The draft FSL utilizes 5 criteria areas: Mission Criticality, Facility Symbolism, Facility Population, Facility Size and Threat to Tenant Agencies; RIEMA is considering adding criteria to address vulnerabilities identified in the CIAT.[62]

Many of these facilities are represented in the Rhode Island Geographic Information System (RIGIS) software. The RIGIS critical facility database can be used to inform microgrid planning, for example by depicting flood zone locations, or determining the type and location of proximal critical facilities that might be considered for inclusion in a microgrid. See Appendix C, Table AC-2 for a representative list of information contained in RIGIS. Currently the planning value of that information is somewhat limited. There remain common barriers to development of microgrids that include multiple facilities which are owned by different parties, or which require power distribution across a public right of way.

Figure A-3 below depicts locations of RI critical facilities from the 2014 Hazard Mitigation Plan Update; this list has grown since then as a result of the RIEMA RICIPP process.

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[60] John McCoy, RIEMA, personal communications, Sep. 12th, 2016.

[61] For example, a research facility containing highly toxic gases might have a high resilience/redundancy score due to its numerous safety features. But if that research facility is in a very densely populated area and a catastrophic disruption would pose a toxic exposure risk to large numbers of people, it might receive a higher criticality score than a different facility with comparable toxic hazards and minimal safety features that is in an area of very low population density.

[62] John McCoy, RIEMA, personal communications, Mar. 22nd, 2017.

Figure A-3: Rhode Island State-Owned and Critical Facilities[63]

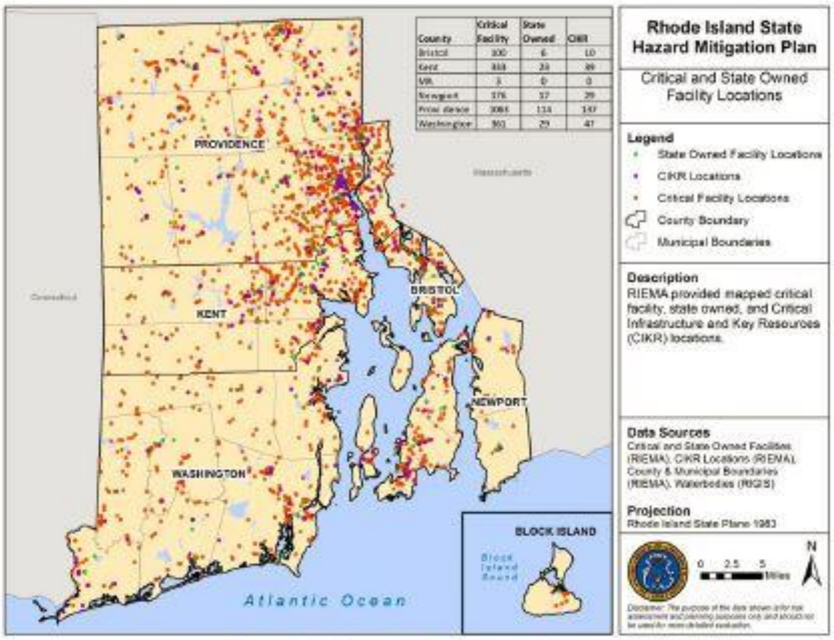

Figure 4. State-owned and critical facilities.

<u>Rhode Island critical facility prioritization</u>

OER microgrid program administrators would need a methodology for prioritization of critical facilities to inform allocation of limited resources, and help determine where to get the greatest benefits for its funding. Two approaches to program implementation have differing implications for how OER might apply prioritization criteria, described below:

A. *"Bottom Up" approach*: The microgrid program team solicits funding applications from eligible projects (*e.g.*, issues an RFP), evaluates and ranks applicant projects according to qualitative and quantitative attributes, and funds projects with the best cost/benefit ratio or highest score.
B. *"Top Down" approach*: The microgrid program team reviews a database of critical facilities, evaluates and ranks those facilities according to qualitative and quantitative attributes, and reaches out to those critical facility locations or sectors with the best cost/benefit ratio or highest score to provide program support.

The approaches are not mutually exclusive and can be implemented in a parallel and complementarily manner.

RIEMA information. Life Line sector facilities are prioritized over other sectors; within each sector SSPs and SLAs are designating priority facilities. CIAT scores indicate criticality of

[63] RIHMP 2014, p. 50.

surveyed facilities.

Policy recommendation: OER could require facilities that apply for microgrid program funding to complete a RIEMA CIAT survey. The survey's energy-related questions could be expanded to collect additional energy assurance information such as annual energy use and cost; critical loads including mission-critical energy-using systems and HVAC systems type; BUG characteristics (*e.g.*, size or fuel type, or presence of additional onsite distributed energy resources (*e.g.*, solar photovoltaics or combined heat and power systems). Microgrid funding applications could also collect this type of information.

Cost-Benefit Analysis (CBA). CBA calculations provide Key Performance Indicators (KPIs), such as $/kW of DER capacity, which could inform microgrid project evaluation. (See Part C for further discussion.) Typical construction and retrofit project CBA includes only standard microeconomic factors, *i.e.*, project-specific direct costs and savings to inform Net Present Value, Return on Investment or Simple Payback Period calculations. OER also wants to evaluate factors that can be considered more macroeconomic or external to a microgrid or facility owner's project finance related criteria; *e.g.*, costs and benefits to the EPS, society, the economy and the environment.

Indirect, non-traditional or "macroeconomic" factors. Microgrids and DERs convey numerous "bigger picture" costs and benefits that typically are not reflected within standard microeconomic project financial analysis, can be hard to quantify, and often are not readily monetized. Docket 4600's Total Resource Cost Test organizes benefit/cost aspects according to where the effects accrue: Power System Level, Customer Level and Societal Level. These "beyond the customer meter" factors include, but are not limited to:

- Costs savings and reductions for grid operators and ratepayers
    - Dispatching microgrid generation provides peak load reduction or local voltage support, resulting in avoided or deferred grid capacity additions or operations and maintenance costs in transmission, distribution and substation assets
    - Reduction in system "line losses"
    - Reduction in electricity prices due to reduced demand
- Avoided costs of outages for critical facilities, local businesses, communities and insurers
- Avoided costs of emissions for cleaner DERs
    - Criteria pollutant reductions
    - Social cost of carbon
    - Improved local air quality
- Public health and safety benefits
    - fewer deaths and injuries during disruptions or due to emissions
- Safe shelter for vulnerable populations / demographics
    - Low to moderate income
    - Children and elderly
    - Disabled, medically dependent
    - Domestic violence shelter
    - Transitional housing, corrections

- Geographic preferences
  - Dispersion across state
  - Location in HUD or USDA funding-eligible area
  - Avoidance of flood zones)
- Economic development benefits
  - Local job creation
  - Technological innovation
  - Attraction of industries with power reliability and energy services
- Contribution to meeting State goals
  - Deployment of renewable energy in State facilities
- National security benefits
  - Reduced oil dependence
  - Increased cybersecurity

There are two primary options for quantifying these types of factors for the purposes of an OER microgrid program, “Economic Valuation” and “Point Scoring” (see Section C1 for further discussion):

- *Economic Valuation method*. Macroeconomic factors could be assigned monetary value using reference criteria such as are contained in Docket 4600’s Total Resource Cost Test, or the NY Prize CBA tool. This approach provides more objective, precise (if not accurate) information that can be integrated with “microeconomic” analysis using a dollar value common denominator. Valuation of program goals in dollar terms can be complex and more subjective, such as the added value when a microgrid serves a low to moderate income demographic. Developing this detailed analysis is more resource-intensive for both the program and its participants. If this approach is taken, OER should provide a detailed template and guidance for applicants to apply the appropriate conversion factors to their project, and/or support applicant CBA with funding or technical assistance teams.
- *Point Scoring method*. A streamlined scoring process with abstracted values representing macroeconomic factors and program preferences could simplify evaluation of funding applications. This approach provides information that is more subjective and less accurate, precise and detailed than the Economic Valuation method, and cannot be integrated with “microeconomic” analysis in monetary terms but rather is used in parallel. This abstracted analysis is less resource-intensive for both the program and its participants. If this approach is taken, the OER team could score funding applications based on information provided in the applications.

A common question vexes energy assurance and emergency preparedness planners: What is the value of resilience? The Economic Valuation method attempts to put a dollar value on the answer, at least in the microgrid context.

<u>Policy recommendation</u>: OER should use the Point Scoring method to simplify the process and conserve program and project resources. This authors suggest a scoring template in Table C-1, which OER can modify as desired.

Public Track and Unique Asset Track options. The basic structure of all the state microgrid programs to date (*e.g.*, CA, CT, MA, NJ, NY) has been to make available funding and other support to eligible applicants via a competitive solicitation. OER could consider a complementary approach to provide more targeted support to unique assets and critical facilities that the Governor can call upon during emergencies.

Policy recommendation: OER could have a two-track approach to identifying and prioritizing critical facilities in a microgrid program: a bottom-up "Public Track" and a top-down "Unique Asset" track.

The "Public Track" approach would be similar in structure to other state microgrid funding programs. Most of the recommendations of this report are intended to inform creation of this type of program. OER could issue an RFP solicitation for municipalities and other critical facility owners to apply for microgrid funding support. This "bottom-up" approach would allow any project that meets the RFP-specified criteria to respond. Applications would be scored based on criteria including a cost/benefit analysis, and a scoring factors that reflect OER program objectives.

A complementary "Unique Asset Track" would take a "top-down" approach: OER would convene an Interagency Working Group (IWG) that includes RIEMA and other agencies as appropriate. The IWG would identify highly critical facilities that provide or enable unique assets and services during a declared emergency. These Unique Assets (UAs) could include, but are not limited to:

- State Emergency Operations Center
- National Guard specialized ground units and armories (*e.g.*, mobile generators, fuel tankers, engineers with heavy equipment, communications, water purification, mobile hospitals, etc.)
- National Guard and other state-owned rotary- and fixed-wing aviation assets
- State agency specialized first responder teams (*e.g.*, collapse rescue, canine, search and rescue, hazardous materials and radiological incident emergency response, Explosive Ordinance Disposal, marine rescue and spill response, etc.)
- State-owned or quasi-public transportation UAs (*e.g.*, airports)

The IWG would reach out to Unique Assets (UAs) and offer funding or other assistance to encourage microgrid development. Track implementation options include:

C. UAs could be solicited to participate in the Public Track application process, and could receive a preferential scoring factor.
D. The UA Track could be conducted as a separate parallel effort to the Public Track, with discrete dedicated funds and outreach.

The program goal would be to utilize microgrid DERs to extend facility-based operations beyond 72 hours (the typical onsite diesel BUG fuel storage capacity mandated for critical facilities as per National Electrical Code Article 708 Critical Operations Power Systems). This focus on leveraging cleaner DERs to enhance energy assurance for State UAs would align with existing state energy goals, including:

- Renewable Energy Standard (RES): Goal of 11.5% renewable energy for 2017; this requirement is set to increase by additional 1.5% each year until the goal of 38.5% is reached by 2035
- Governor's E.O. 15-17: Goal of 100% renewable energy for state facilities by 2025
- The Resilient Rhode Island Act: Sets targets for reducing greenhouse emissions to 45% below 1990 levels by 2035 and to 80% below 1990 levels by 2050
- Governor's "1,000 by '20" goal of 1,000 MW of clean energy by 2020, a 1000% increase from the 2016 baseline total of ~100 MW of existing capacity consumption

UAs would be asked to assess their energy assurance strategies, capabilities and facility dependency. If a UA is highly dependent on its base facility, that location could be prioritized for microgrid assistance. If a UA is not facility-dependent due to its ability to relocate personnel and equipment to another location and sustain mission-critical operations, the UA should verify its energy assurance strategy and capability to sustain operations beyond 72 hours at alternate locations. For example, if a specialized team's base facility loses power, and the team can move to an alternate location or staging area, what is that alternate location's grid-independent energy assurance?

OER could consider a top-down outreach approach to private sector UAs as well. Potential high-priority examples include facilities that support service restoration for EPS, natural gas, transportation and communications networks; and State contractors that provide or support UAs, for example as identified resources in emergency preparedness and response plans.

Policy recommendation: OER could prioritize energy assurance for private sector facilities that enable service restoration for the EPS, natural gas and other critical infrastructure networks.

Private sector energy sector critical facilities are discussed in the following section.

3. RI energy system critical infrastructure and interdependencies

The web of critical infrastructure interdependencies is highlighted in simplified form in Figure A-4 below.

Figure A-4: Interdependent Infrastructure Sectors[64]

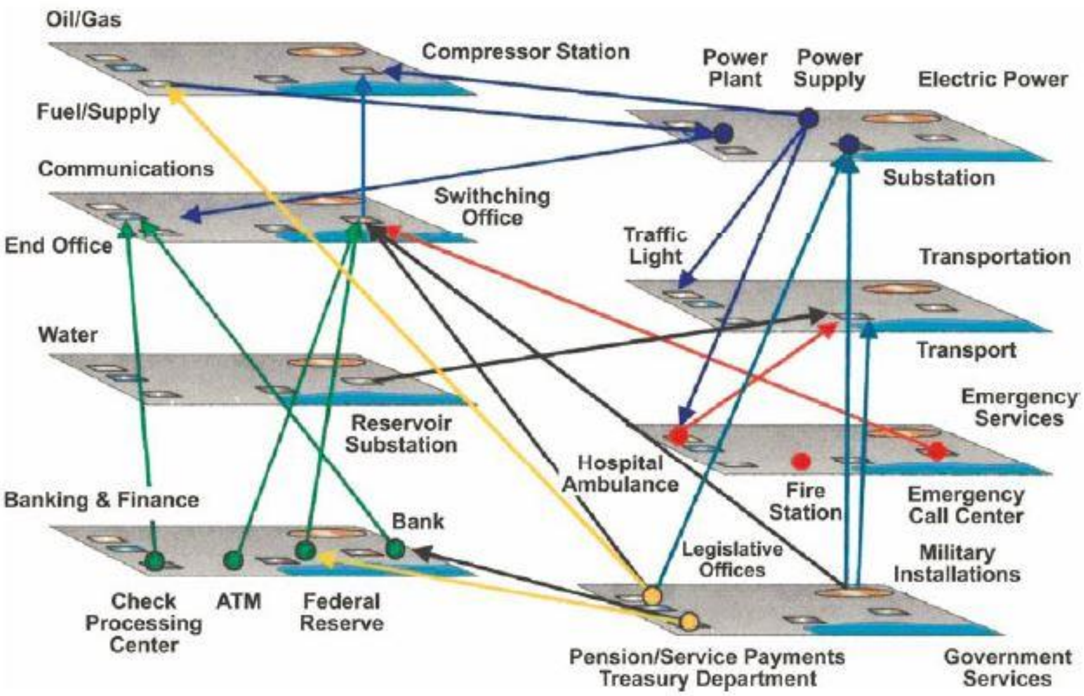

Figure 4. Interdependent Infrastructure Sectors

3.1 Electricity dependency on natural gas

The EPS is arguably the most critical infrastructure, because all other critical infrastructure and facilities depend upon the EPS to function. National Grid's EPS reliability planning and performance are discussed in more detail in section A1.4 and Appendix B.

The EPS depends on the natural gas system, and *vice versa*. RI is almost entirely dependent on natural gas supply for electricity generation, with ~97% of in-state generation capacity fueled by natural gas.[65] Power production comprises ~58% of RI natural gas consumption, with industry using ~8% and other retail customers ~34%.[66] "Natural gas-fired generators in Rhode Island do not receive firm gas transmission. Similar circumstances are anticipated in nearby states. Consequently, a disruption in the supply of natural gas would affect electric supply."[67] It is important to note that gas supply capacity and redundancy provide significant resilience; the non-firm gas supply contracts of the power stations render them more vulnerable to curtailment.[68]

[64] *Report of the Commission to Assess the Threat to the United States from Electromagnetic Pulse (EMP) Attack, Volume 1: Executive Report*, 2004, p. 9. Accessed at: http://www.empcommission.org/docs/empc_exec_rpt.pdf
[65] RIEAP, p. ES-7.
[66] RIEAP, p. ES-9.
[67] RIEAP, p. 9-10.
[68] For further discussion see RIEAP pp. 9-13 & 9-14.

Policy recommendation: OER could consider requiring natural gas fueled microgrids to secure firm supply contracts.

National Grid is the only natural gas Local Distribution Company (LDC) in the state; it does not produce any gas. There are no natural gas wells in RI. Pipelines provide ~93% of the state's supply[69], and RI is effectively at the "end of the line". RI reached 98% of pipeline capacity in 2009[70], which remains sufficient to serve in-state peak demand.[71] Winter gas peak demand is almost double that of non-winter peaks; peaks demand can be almost triple non-peak demand; power production comprises ~50% of peak consumption.[72] Two primary pipelines coming through New York state, each with two offshoot lateral lines, supply ~72% of the state's natural gas and also deliver the ~20% of gas coming from Canada [73]: Algonquin Gas Transmission (AGT) provides ~60% of pipeline capacity and Tennessee Gas Pipeline (TGP) provides ~40%.[74]

Major pipelines disruptions or regional supply curtailment for other reasons that also affect "upstream" states (*e.g.*, CT, MA, NJ, NY) could significantly impact RI's in-state power production capacity. AGT and TGP rely on compressor stations to maintain supply, which require electricity to operate. Loss of a compressor station reduces the amount of delivered gas but would not halt deliveries. In the event of a power outage these compressor stations maintain BUGs fueled by natural gas to continue operation; TGP's BUGs draw their gas from the pipeline itself.[75] Pipeline and lateral redundancy enable the LDC to endure the loss of two compressor stations before it curtails peak day deliveries.[76]

Pipelines are more resilient against severe weather events than are the overhead EPS transmission and distribution (T&D) networks, which are more exposed to wind, precipitation and inundation hazards. Pipelines are more vulnerable to seismic events than the overhead EPS and probably would take longer to repair, although seismic risk to the northeastern pipelines network is low. In the event of a cyberattack the pipelines can be operated in manual mode.[77] A major failure that halts supply on either AGT or TGP could take 16–18 months to repair.[78]

Liquid natural gas (LNG) imports provide ~7% of the state's supply.[79] LNG storage provides a vital buffer and swing supply capacity to help meet short-term demand peaks that exceed pipeline supply capacity. The LDC maintains LNG storage sufficient for ~13 days of peak discharge output.[80]

[69] RIEAP, p. ES-10.
[70] RIEAP, p. 7-14.
[71] RIEAP, p. ES-11.
[72] RIEAP p. 9-11.
[73] RIEAP, p. ES-10. The same source states on p. ES-12 that AGT and TGP provide 77% of the state's natural gas.
[74] RIEAP p. 3-5.
[75] RIEAP, p. 3-8.
[76] RIEAP, p. 9-12.
[77] RIEAP p. 4-21.
[78] RIEAP p. 9-11.
[79] RIEAP p. ES-10.
[80] RIEAP p. 9-13.

In summary, RI is well positioned to withstand the loss of any one major component of its natural gas infrastructure due to redundant supply sources and the LDC's planned excess capacity and storage. But LNG storage can be depleted in 13 days of full output, so disruptions of two weeks or longer could result in supply curtailments.

Delays in service restoration can occur due to customer-side factors as well. Flooding or other circumstances that suddenly shut down local natural gas supply could delay restoration of service due to the slow and labor-intensive process of inspecting and relighting pilot lights one customer at time, a process that could take days or weeks due to demands on specially licensed professionals.[81]

3.2 Liquid fuels supply chain EPS dependence and resilience

Liquid petroleum fuels—particularly gasoline, diesel fuel and building heating oils—provide critical energy services. Supply disruptions ripple through other critical infrastructure and services, and hinder other community and economic functions. Vehicle fuel enable transportation of vital materials and personnel. If people can't get to work and vehicles can't operate, commerce and critical services suffer.[82] These fuels are vital for operating residential and facility BUGs, and for space heating, both essential for shelter in place and other critical missions. (Note that in emergencies, it is technically possible—although illegal and unadvisable—to use diesel fuel in place of #2 oil in home heating furnaces.)

"Unlike natural gas infrastructure, in which Rhode Island is at the end of the pipeline, Rhode Island's petroleum consumers sit at the top of the supply chain pipeline. There are currently six (6) marine terminals within the State, five (5) of which are located in the Providence metropolitan area while the sixth is located in Tiverton…. The six (6) petroleum marine import terminals have a combined storage capacity of over 5 million barrels of refined products. To place this in perspective, Rhode Island purchased approximately 20.7 million barrels of gasoline, kerosene and distillate in all of 2011. The State's most critical petroleum infrastructure are the five marine import terminals….".[83]

Rhode Island's liquid fuel supply chain is vulnerable to disruptions, particularly storm surge. The concentration of 5 of the state's 6 terminals and 90% of the storage capacity along the Providence waterfront increases geographic risk.[84] "Events such as severe weather, hurricanes or earthquakes could impact multiple terminals and disrupt the supply of petroleum to Rhode Island."[85] "For example, during Blizzard NEMO in February 2013, all of the fuel terminals in the State lost electrical power for two days and were unable to provide fuel (i.e. gasoline, diesel, heating oil, jet fuel) to gas stations, homes, airports, and other critical facilities. During Hurricane Sandy…. Fuel terminals were also severely impacted—four out of the six terminals

[81] RIEAP pp. 4-10 & 4-11.
[82] RIEAP p. 9-17.
[83] RIEAP pp. ES-11 and ES-12.
[84] RIEAP p. 9-15.
[85] RIEAP p. ES-13.

were forced to shut down during storm landfall, and the Inland Terminal at Tiverton did not get power back for at least three days."[86]

OER's microgrid program could address a major vulnerability by installing DERs well above storm surge levels to enable grid-independent terminal operations. As of 2014, none of the terminals had on-site BUGs capable of supporting operations. "Marine terminals require an uninterrupted supply of electricity to maintain routine product offloading and rack services. […] Marine terminals generally do not have on-site backup electric generators that can facilitate on-going petroleum supply during a disruption in electric service. […] Today, there are no adequate generators in place at any of the marine terminals. […] One of the petroleum terminals in Rhode Island does have a backup generator that is warehoused in Texas and could be transported to Rhode Island. However, this process could require several days for transportation, delivery, installation and operation. […] "[87]

<u>Policy recommendation</u>: OER could prioritize petroleum marine terminals and storage facilities for microgrid support, *e.g.*, by preferential scoring and/or including them in a Unique Asset Track.

Downstream of the terminals, petroleum delivery relies on tanker trucks, so the distribution network can function if the terminals are operating and the roads are passable. Storage capacity provides a time buffer if the terminals cannot operate but storage facilities are operable and roads are open. "Rhode Island's petroleum wholesalers report that average inventory levels [are] sufficient to meet the State's needs for approximately two (2) to three (3) weeks. Therefore, hazards that are capable of disrupting the petroleum supply chain for more than two (2) weeks could result in shortages for the state."[88]

Gas stations are the vital interface between the gasoline and diesel supply chain and the public. "Routine automobile and truck transportation are vulnerable to disruptions in electric supply, which could set off as ripple effect that adversely impacts commerce and emergency services throughout the State. The cause of such disruption is that retail service stations utilize electricity to operate pumps for fueling vehicles. The New England Service Station and Auto Repair Association reports that it is uncommon for service stations to have a backup generator. Consequently, a prolonged electric outage would effectively close all retail service stations and preclude vehicles from being re-fueled…. Rhode Island is not prepared to respond to such impacts."[89] This situation presents an opportunity for OER to enhance service station energy assurance with sector-specific dedicated microgrid support.

<u>Policy recommendation</u>: OER could prioritize service stations for microgrid support, *e.g.*, by preferential scoring and/or including them in a Unique Asset Track focused exclusively on gas stations.

[86] OER, RFP # 7549749 *Resilient Microgrids for Critical Services*, 2015, p. 5.
[87] RIEAP, pp. 4-23 and 9-15 (quotes interspersed out of sequence).
[88] RIEAP, pp. 9-15 and 9-17.
[89] RIEAP p. 9-17.

OER could develop a "Service Station Track" programmatic effort focused exclusively on gas stations. Outreach could target chain and franchise owners of service stations; corporate support would be valuable. Track features could include:

- Require, reward or prefer at least one fuel pump at each location that features backup manual operation equipment, *e.g.*, as part of the retrofit project and/or whenever new pumps are installed.
- Allow funding of gasoline- or diesel-fueled BUGs utilizing fuels stored and sold onsite; consider requiring only BUGs with USEPA Tier 4-compliant emissions controls.
- Develop a modular approach, *e.g.*, standardized rooftop and/or pump canopy-mounted PV systems combined with energy storage sufficient to operate pumps.
- Combine energy efficiency improvements such as LED lighting and efficient refrigeration with onsite generation.

The effort could utilize RIIB C-PACE funding, and consider soliciting dedicated contractor teams to specialize in this type of critical facility energy assurance.

NJ has a Retail Fuel Station Energy Resilience Program.[90] "The State has awarded nearly $7 million in grants from the federal Hazard Mitigation Gran Program to more than 230 fuel stations located along key thoroughfares identified by state homeland security and emergency management personnel. Eligible station owners used the funds to purchase generators or permanent connection points for mobile generators, also known as 'quick connects.' Stations were targeted for the program based on factors including proximity to evacuation routes and fuel storage capacity."[91] Mass Clean Energy Center (MA CEC) is developing a similar program.

[90] http://www.state.nj.us/governor/news/news/552013/approved/20131021b.html
[91] See "Retail Fuel Station Energy Resilience Program" section and links at: http://www.state.nj.us/dep/aqes/ormr-energy-resiliency.html

PART B: MICROGRID TECHNOLOGIES AND APPLICATIONS

1. Microgrid definition

There are numerous definitions of "microgrid." The U.S. Department of Energy (DOE) Microgrid Exchange Group definition is perhaps the most widely referenced: "A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode."

An electrical load is an electrical component or portion of a circuit that consumes electric power. The DOE microgrid definition does not specify whether a "group of interconnected loads" can be applied to devices and systems contained within a single building or facility that each use electricity (e.g., lighting, HVAC, elevators, life safety systems, etc.), or whether each facility in a microgrid is considered one aggregated load.

This is relevant for microgrid planning, because installing distributed energy resources (DERs) behind the meter (BTM) of a single-metered building to enable grid-independent operations is a relatively straightforward situation, as familiar as any building with a backup generator (BUG) and an automatic transfer switch (ATS). But connecting individually-metered buildings to shared DERs in a microgrid configuration so that multiple facilities can disconnect from the electric power system (EPS) or "grid" is a situation that can risk triggering a challenge to the regulated utility monopoly franchise. Connecticut's state-sponsored microgrid funding program defines a "microgrid" as containing two or more separately-metered critical facilities.

For the purposes of this report to inform development of a state microgrid program for enhanced energy assurance at critical facilities, we allow that a single facility can be a microgrid.[92] Under current conditions, the most common least-cost opportunities to retrofit critical facilities with DERs are single facility BTM microgrid projects, rather than multiple-facility microgrid configurations. This is the case due to technical, locational, and legal or regulatory factors.

Definitions of microgrid types, configurations and ownership models are discussed in more detail in Section B3 and B7. For the purposes of this Part of the report, we reference the microgrid typology suggested by the New Jersey Board of Public Utilities (NJBPU)[93], with minor modifications:

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[92] The authors acknowledge that given the prefix "micro-" means "one-millionth," and estimates indicate that there are almost 2 billion buildings worldwide and roughly 120 million residential and commercial buildings in the U.S., perhaps the term "nanogrid"(*i.e.*, one-billionth of a grid) is a more accurate descriptive for a single-facility islandable configuration.

[93] NJBPU, *Microgrid Report*, 2016, p.17.

Microgrid type	DERs	Facilities	Meters	Facility owners
Level 1 single facility	1–2+	1	1	1
Level 2 campus	1–2+	2+	1–2+	1
Level 3 multi-user community	1–2+	2+	2+	2+

1. Microgrids general purpose and applications

General purpose

Microgrids serve many purposes and provide multiple services and benefits, including:

Energy assurance for critical facility mission assurance, continuity of operations and resilience. OER requested this report to address resilient microgrids for critical services for the State of Rhode Island. Microgrids can enable critical facilities to operate during prolonged grid outages during disasters, providing vital community support.

Reduced outage costs. Microgrids can reduce the cost of outages to facility owners and the communities that rely on them, including longer-term community economic resilience by helping smaller businesses survive prolonged outages.

Facility owner cost reduction and/or revenue generation. Microgrids can provide lower-cost energy, and sell power or services such as demand response, voltage support and frequency regulation to the grid. Level 2 campus microgrids are generally best positioned to maximize the benefits of shared energy systems supporting clustered facilities.

Grid operator cost reductions and lower customer electricity costs. Microgrids can support grid operations with dispatchable generation and load, and facilitate service restoration after outages. Microgrids can help defer EPS capacity investments and O&M costs by reducing EPS congestion and peak loads. Minimizing grid costs can help minimize electricity costs.

Increased deployment of renewable resources and improved environmental quality. RI has renewable energy targets. Intermittent renewable distributed generation (DR) such as solar and wind power can pose challenges for remote grid operators. Microgrids can help manage large concentrations of renewable generation at the local level to improve their safety and economics. Renewable resources have lower emissions than fossil fuel generation, contributing to public and environmental health.

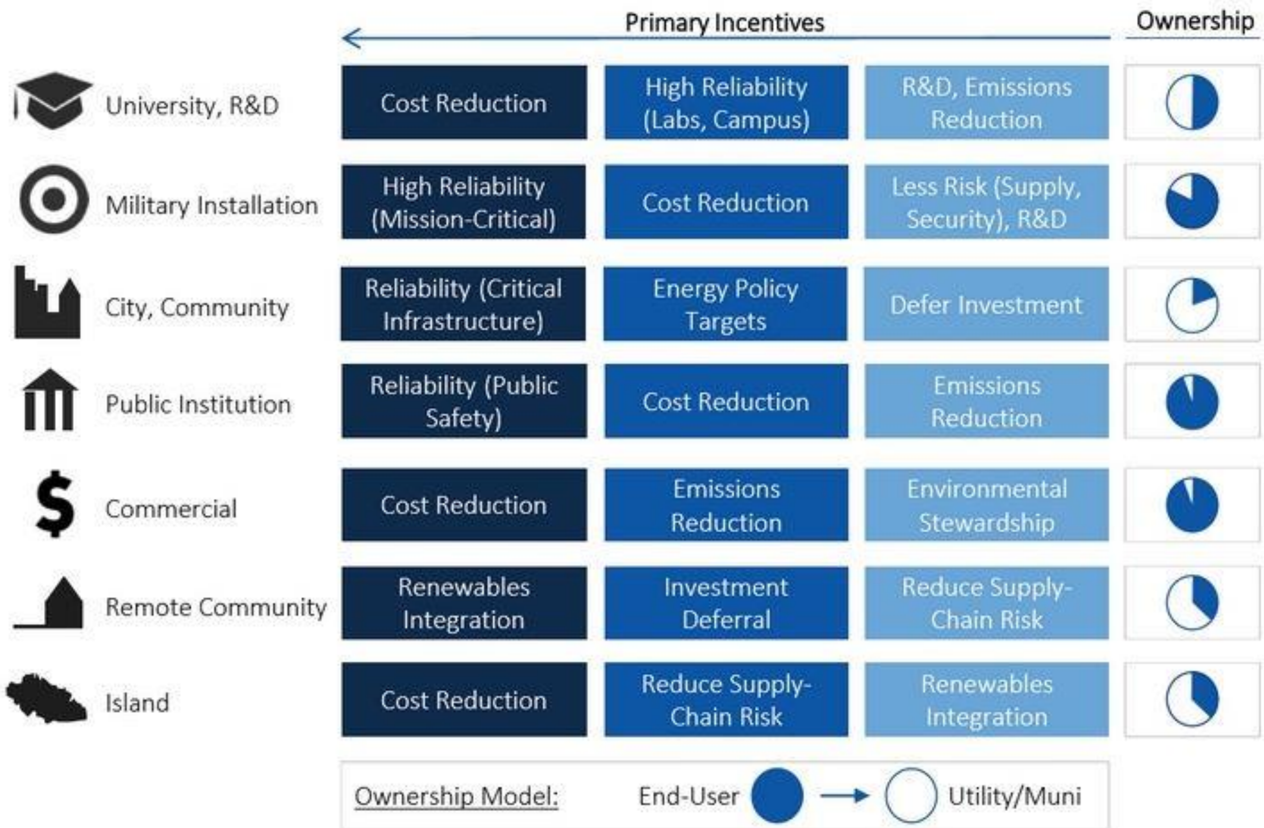
Avoided grid losses and improved DER utilization. Microgrids locate DERs close to the end user, avoiding transmission and distribution losses.

Greater local control over energy resources. Microgrids enable owners to combine DERs, energy efficiency, and energy management at the facility level and local scale to enable maximum control over equipment investments and operational strategies to deliver energy

services for optimal value in an integrated approach.
In summary, microgrids can help realize multiple public policy objectives and energy systems benefits.

Figure B-1 depicts GreenTechMedia's organization of microgrid owners and applications, and incentives or benefits of installing a microgrid.

Figure B-1: Ranking of Microgrid Implementation Drivers by End Customer Type[94]



Applications

Level 1 single-facility microgrids include all critical facility types and are typically used primarily for energy assurance and secondarily to maximize DER benefits during "blue sky" normal operation.

Level 2 campus microgrids most commonly include military bases, higher education campuses, health care complexes, high-density residential developments, industrial parks, and remote or island communities, as well as corporate campuses and prisons. Utility cost benefits and energy assurance are primary objectives.

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94 https://www.greentechmedia.com/articles/read/3-Trends-That-Suggest-Microgrids-Are-for-More-Than-Just-Resiliency

Level 3 multi-user community microgrids are very rare although several projects are under development. Applications include provision of electric service at the community scale when connection to a larger "macrogrid" is too costly or otherwise prohibitive (*e.g.*, remote communities or islands); and energy services management at the local scale by a private or public utility, local cooperative, multi-property real estate development, or other microgrid owner than can disconnect from the macrogrid.

The Minnesota microgrid report described microgrid applications by organizing critical facilities into three asset categories, defined by the critical mission: crisis response and management; public health and safety; and basic needs and services. See Figure B-2.

Figure B-2: Microgrid Applications by Critical Facility Asset Categories[95]

Asset Category	Examples	Priorities and Microgrid Factors
Crisis Response and Management	■ Utility and transportation crew dispatch, supply, and staging centers ■ Government command and control centers ■ Telecom infrastructure	■ Critical to facilitate repair and recovery, minimizing the damage from a crisis and avoiding cascading effects on interdependent systems. ■ Microgrids can be more effective when crisis management facilities are clustered together, allowing asset sharing and load diversity.
Public Health and Safety	■ Hospitals and other health care facilities ■ Police and fire departments ■ Public water systems	■ Vital to support first response, medical care, and law and order. ■ Many such facilities already have backup power systems that can be upgraded with microgrid technologies to increase their effectiveness.
Basic Needs and Services	■ Storm shelters and temporary housing ■ Grocery stores ■ Fuel infrastructure, including gas stations ■ Public transportation and transit systems	■ Vital products and services to support basic needs of residents, and provide shelter and vital mobility for displaced and at-risk populations. ■ Load-management systems and protocols can help conserve fuel and extend effectiveness of basic backup power supplies.

Figure 1-2: Energy Assurance Priorities and Microgrid Applications

[95] Microgrid Institute, *Minnesota Microgrids: Barriers, Opportunities, and Pathways Toward Energy Assurance*, 2013, p. 17.

2. Microgrid types

Microgrid types can be distinguished by application as well as technical and ownership attributes. See further discussion of ownership types in Section B7.

Remote microgrids: Islands, remote communities and commercial installations (e.g., mines). This is perhaps the most common microgrid type worldwide, although not in the "Lower 48" U.S. states where the grid is pervasive. "It is estimated between 100 and 200 remote microgrids are fully functional today, providing power in the absence of traditional grid infrastructure."[96] Examples include many Alaskan remote communities and islands such as Kodiak Island, Hawaiian islands and U.S. territories are effectively microgrids, albeit often utility-owned. The only remote microgrid in Rhode Island in recent times was Block Island, a diesel-generator-based remote microgrid before National Grid connected the island to the mainland with an undersea cable in 2016.

Level 1 microgrids: Single- or multiple-DER, Single facility, single owner, BTM installations. This is the most common retrofit energy assurance opportunity in the U.S., although some would argue that it takes two or more facilities to constitute a microgrid. Examples include:

- Scripps Ranch Recreation Center, San Diego, CA, a PV+BES+BUG microgrid at a community center that serves as a shelter and emergency operations center.[97]
- McAlpine Creek Demonstration Project, Charlotte, NC, a utility-owned PV+BES installation at a substation that can isolate and supply an adjacent fire station (which also has a BUG).[98]

Level 2 campus microgrids: Single- or multiple-DER, multiple facility, single owner installations. This configuration is the most common multi-facility microgrid type. A campus microgrid is distinguished by shared DERs connect multiple facilities. Typically these configurations distribute power across streets and other rights of way, which can face legal barriers or require permission from the utility or authorities having jurisdiction (AHJ). However, this is not an issue when the microgrid, its facilities and the surrounding property share the same owner. Examples include:

- John O. Pastore Center, Cranston, RI, a State medical and corrections critical facility CHP-based campus microgrid.[99]
- The Medical Area Total Plant (MATEP), Boston, MA with independently-owned CHP providing steam, chilled water and electricity to a group of clinical, research and teaching institutions.[100]
- Princeton University, Princeton, NJ microgrid including customer-owned 15 MW CHP,

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[96] ILSR, *Mighty Microgrids*, 2016, p. 7.
[97] http://www.cleanegroup.org/ceg-projects/resilient-power-project/featured-installations/scripps-ranch-microgrid/
[98] http://www.cleanegroup.org/ceg-projects/resilient-power-project/featured-installations/mcalpine-creek/
[99] http://www.noresco.com/energy-services/en/us/pastore/index-2.html
[100] http://www.matep.com/

5.3 MW PV and Thermal Energy Storage (TES).[101]

Utility owned/operated microgrid. A regulated vertically-integrated electric utility or an unbundled electricity distribution company (EDC) owns and operates the EPS infrastructure, the microgrid distribution infrastructure, and the DERs. There are relatively few examples in the mainland U.S., and they are uncommon among EDCs in restructured or "deregulated" electricity markets in states including RI, in part due to restrictions on EDC ownership of generation capacity. (Exceptions include an unknown number of municipal utilities and electric cooperatives that are able to island from the EPS.) Examples include:

- Green Mountain Power's Stafford Hill, VT, with a utility-owned 2.5 MW PV plus 4 MW / 3.4 MWh battery energy storage (BES) installation that can provide grid support as well as form a Level 1 single-facility microgrid at adjacent Rutland High School, a public emergency shelter.[102]

Utility distribution microgrids—Hybrid ownership model. In hybrid ownership models, a regulated electric utility or EDC owns and operates the EPS infrastructure and the microgrid distribution infrastructure, while customers or third parties own the DERs. Alternative examples could include utility ownership of generation and customer or third party ownership of energy storage. There are relatively few examples in the mainland U.S., and they are uncommon among EDCs in restructured or "deregulated" electricity markets in states including RI, in part due to restrictions on EDC ownership of generation capacity. Examples include:

- San Diego Gas and Electric's Borrego Springs, CA where SDG&E owns the distribution system and various DER owners serve a community of 2,800 people.[103]

Virtual microgrids. "Virtual microgrids (vgrids) cover DER at multiple sites but are coordinated such that they can be presented to the grid as a single controlled entity. Very few demonstrations of vgrids exist, but they have been proposed in the literature."[104] Akin to a Virtual Power Plant (VPP) and aggregated demand response providers, this configuration is enabled by software, controls and communications that can coordinate multiple dispersed microgrid locations to act as one controlled entity. Some demand response programs could be considered a form of vgrid, where dispersed facilities shed load or dispatch their BUGs upon coordinated remote command to remove those loads from the EPS. Examples include:

- Gridscape's Fremont, CA Fire Station microgrids. Three fire stations are being retrofitted with PV plus BES systems that could be controlled to island from the EPS.[105]

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[101] https://facilities.princeton.edu/news/case-study-microgrid-princeton-university and ILSR, *Mighty Microgrids*, 2016, p. 10.

[102] http://www.cleanegroup.org/ceg-projects/resilient-power-project/featured-installations/stafford-hill/

[103] https://building-microgrid.lbl.gov/borrego-springs

[104] https://building-microgrid.lbl.gov/types-microgrids

[105] http://www.energy.ca.gov/research/epic/documents/2016-09-06_workshop/presentations/09%20Gridscape-Fremont%20Fire%20Stations.pdf

Level 3 Multi-user community microgrid. A multi-user microgrid comprises multiple customers and facilities with separate owners and electric meters, located on private properties connected by public roads and rights of way (ROW). This is what many people think of when they imagine a microgrid—yet they're rare (so far) in the U.S. This type of microgrid will remain unusual in both EDC and vertically-integrated utility service territories without reshaping the current regulatory structure. See section D2.2 for further discussion. A common conception of Level 3 microgrids is a cluster of public sector critical facilities, a downtown core or commercial and community centers that can remain energized during grid outages to provide important community functions and contribute to quality of life during extended blackouts. The Massachusetts Clean Energy Center (Mass CEC), NY Prize program, and NJ "Town Center DER microgrids" effort seek to develop these types of projects. The Maryland Microgrid Task Force uses the term "public purpose microgrids" to describe this objective and proposes strategies to achieve them. Only the NY and MD efforts are occurring in the context of bigger-picture exploration of new regulation regimes. Examples include:

- Burrstone Energy Center, Utica, NY where a privately-owned 3.6 MW CHP installation provides power, steam and hot water to serve hospital, nursing home and college facilities in a "virtual campus" connected across public and utility rights of way (ROW) with utility and AHJ permission.[106]
- Parkville neighborhood microgrid in Hartford, CT, a public-private-utility partnership with a fuel cell serving an elementary school, library, senior center, health center and gas station on a single city block that can island from the EPS.[107]
- Philadelphia Navy Yard development including numerous commercial and residential properties in a campus configuration on a former military base redeveloped for private use.[108]

National Grid has proposed a pilot demonstration project of a Level 3 community microgrid with a hybrid utility-third party ownership model in Potsdam, NY, as part of the NY Prize program. This project is under development and has evolved since the original and updated descriptions were submitted to the NY Prize program. As initially described, the project included innovative PPA arrangements and custom tariffs[109].

These ownership models are a streamlined version of the many types and models described in the literature. See resources suggested below for more detailed discussion and alternative models.

[106] http://www.powerbycogen.com/burrstone-energy-center
[107] http://www.2017energyexchange.com/wp-content/tracks/track4/T4S9_Matta.pdf and https://www.epa.gov/sites/production/files/2015-07/documents/a_chp_policy_case_study_-_city_of_hartford_connecticut.pdf
[108] http://navyyard.org/about-the-campus/energy-innovations/ and http://www.pjm.com/~/media/about-pjm/emerging-technologies/20160209-t-and-d-world%20-philadelphia-navy-yard-article.ashx
[109] See "Resiliency Demonstration in Potsdam" accessed at: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9?OpenDocument

For further reading:

- Collections of brief case study examples of microgrids are provided by Lawrence Berkeley National Laboratory (worldwide)[110], and the Resilient Power Project (U.S.)[111].
- NYSERDA, *Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State*, 2010, "Microgrid Ownership and Service Models", pp. 22–29, provides a detailed discussion of multiple ownership and service types. Appendix A provides detailed case studies of six microgrid projects in the U.S and the UK.
- KEMA (MA), *Microgrids – Benefits, Models, Barriers and Suggested Policy Initiatives for the Commonwealth of Massachusetts*, 2014, Section 6 describes business models including distribution company, single-user, hybrid and multi-user (non-utility) microgrids.[112]
- Resiliency Through Microgrids Task Force, *Maryland Resiliency through Microgrids Task Force Report*, 2014, describes ownership models and applications including utility or third-party-owned Public Purpose Microgrids, New Asset Microgrids and Local Microgrid Operators.[113]

3. Overview of MG technologies

This section provides an overview of microgrid technologies. Rather than repeat the content of the many good sources of information available on these topics, for brevity the authors will discuss these issues with somewhat subjective commentary and refer to resources for further reading. The relative amount of text per given topic is not to be correlated with the relative importance of the subject.

4.1 Demand Side: Critical Loads

This section provides a brief overview of critical load characteristics and considerations, and of DERs that can help reduce loads, highlighting their respective advantages, limitations and strategies for microgrid applications.

Critical loads

Critical facilities (CFs) support critical missions, which requires that the facility have energy supply for its critical loads (CLs) to enable personnel to remain in the CF and operate essential equipment. This is the primary purpose of a CF microgrid. The mission determines what loads are critical. Most CFs have a common set of "core loads" that enable occupants to remain

[110] https://building-microgrid.lbl.gov/examples-microgrids
[111] http://www.cleanegroup.org/ceg-projects/resilient-power-project/featured-installations/
[112] http://www.masscec.com/microgrids-%E2%80%93-benefits-models-barriers-and-suggested-policy-initiatives-commonwealth-massachusetts
[113] MD 2014, accessed at: http://energy.maryland.gov/Pages/resiliency.aspx

indoors in safety and comfort, *e.g.*, life safety systems, lighting, HVAC, potable water supply, and wastewater removal. Additional facility-specific CLs enable mission critical operations, *e.g.*, communications, specialized equipment.

Requirements for maintaining safe indoors temperatures under the extremes of four-season conditions should be considered, and can be met using both passive and active measures. Passive measures required no additional fuel energy input, and include Trombe walls and other solar thermal heating, aperture shading such as *brise soleil* to reduce heat gain, natural ventilation techniques, and insulation. Active measures include HVAC equipment. Space conditioning requirements should be considered from both the occupant and structural perspective. Humans need a safe temperature ranges to perform critical missions or to shelter in place in safety, if not in comfort. In colloquial terms from a structure's perspective, a building generally doesn't care if it is hot, but it does care if it is cold, as pipes can freeze and cause disabling damage.

For further reading:

- University of Michigan and U.S. Green Building Council, *Green Building and Climate Resilience: Understanding Impacts and Preparing for Changing Conditions*, 2011[114]
- Resilient Design Institute[115]

Load shedding and isolation: Microgrid-powered CLs are typically a subset of a facility's total loads during normal operation under grid-connected "blue sky" conditions. Ideally microgrid DERs energize only critical loads plus a minimum of non-essential loads during grid-independent operations, to avoid investment in unnecessary DER capacity. This is accomplished by segregating essential loads from non-essential loads with a critical loads circuit or load-shedding scheme. Sometimes a facility is not wired to isolate all non-essential loads, and rewiring a new critical load panel or circuit is cost-prohibitive. Trade-offs can be made between load isolation and added generation capacity. A "load isolation factor" reflects the percentage of total load that is non-essential but can't be shed during grid-independent operations, which can be equal to an additional 10%–30% or more of "island mode" load.

DER sizing considerations: Economic sizing of microgrid DERs should consider CL requirements, plus an isolation factor where applicable), plus a reserve margin of excess capacity to address future growth or temporary spikes such as motor inrush currents on start-up. A 20% reserve margin is recommended, and for example is required in the CT microgrid program. Ideally constant-duty DERs should be sized sufficiently large to serve CLs in island mode, and operate "base loaded" at full economic output during normal grid-connected operations.

Energy efficiency: Critical loads' energy requirements vary, and energy efficiency can deliver energy services at lower demand and consumption. Energy efficiency is generally cheaper than onsite generation, and load reduction opportunities should be maximized before sizing onsite

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[114] Accessible at: http://www.usgbc.org/resources/green-building-and-climate-resilience-understanding-impacts-and-preparing-changing-conditi

[115] www.resileintdesign.org

DERs. Deep energy retrofits can reduce loads by 50% or more. Passive energy design features such as solar heating and high insulation can enable CFs to remain habitable during power curtailments with minimum supplied energy.

Load characteristics: Load characteristics inform DER selection and microgrid design. Some specialized equipment such as sensitive electronics have low fault tolerance and require high power quality. DERs must be capable of following the CF load as it changes up or down in island mode. Some DERs are not capable of safely and rapidly ramping output up or down to meet sudden "step function" changes in blocks of load. For example, large electric motors and other devices have inrush currents on start-up that can briefly spike their power draw by a factor of two to five times (or more) greater than their normal operating load. Variable frequency drives and "soft start" devices can help limit motor inrush current and reduce device energy use. Microgrid controls might incorporate load shedding capabilities. Rapidly-responsive energy storage such as capacitor banks can help provide a buffer for microgrid generation by charging or discharging as needed to shape or serve load swings.

Microgrids that include multiple CFs should consider the complementary aspects of each facility's energy requirements and load profile that can inform economic DER selection and operation. For example, many typical RI municipal CFs (*e.g.*, Town Hall, shelter school, fire station) have energy use patterns similar to a commercial office building: basic building function "core loads" dominate total loads, there is little energy-intensive specialized equipment, and load profiles reflect a weekday single-shift usage with business hour peaks and relatively little nighttime load. This profile might match PV-plus-battery system output well, with peak energy production during daylight hours. But to facilitate an economical CHP installation that needs to operate at a high level of output for the maximum percentage of the year, this type of municipal CF might be paired with a nearby residential building (*e.g.*, MFH, nursing home), which will use more energy at night while residents are inside. The combination of complementary load profiles could make a good CHP application: one CF with lower electrical load and higher thermal load, plus a facility with lower electrical load and higher thermal load. This type of opportunity is a good motive for enabling less-than-critical facilities to participate in a microgrid, if their energy use profile facilitates more economical DER installations.

For further reading:

- NYSERDA 2014, *Microgrids for Critical Facility Resiliency in New York State*, Section 5.3.1 Supplying Critical Infrastructure, p. 54 provides a list of options for supplying CLs.

DERs for Facility Load Reduction: Solar Thermal

Overview: Solar thermal (ST) systems can generate hot water from the sun with little or no electricity other than for circulation pumps. Rooftop or ground-mount panels can generate heating hot water (HHW) or domestic hot water (DHW).

Advantages: Innovations in this mature technology such as with vacuum tubes that enable ST systems to provide a range of output temperatures. This largely passive source of thermal energy reduces facility thermal and electrical loads, lowers emissions and contributes to resilience.

Limitations: A limited range of output temperatures defines suitable thermal applications. ST can be a costly retrofit, with case-specific benefits. Recommended strategies:

Strategies: Consider ST use for passive energy assurance and load reduction, particularly to serve HVAC or DHW loads in island mode with little or no electrical load, where CHP is not an economical option, or to complement limited CHP capacity.

<u>DERs for Facility Load Reduction: Heat Pumps</u>

Overview: Compressor-based heat pumps (HPs) are the most electrically-efficient method of transferring thermal energy (*e.g.*, from indoors to outdoors for cooling, or vice versa for heating), and can be used for space conditioning or DHW. Ground-source heat pumps (GSHPs, also called "geothermal") and water-source heat pumps (WSHPs) tend to be more energy efficient than air-source heat pumps (ASHPs), but are more dependent on conducive site conditions. Numerous recent MFH buildings provide heating and cooling with an HP in each apartment, in cases connected to a condenser water loop that links the HPs to a boiler for greater efficiency; this type of system might be able to utilize byproduct heat from CHP. Through-wall split system ASHPs can be economical retrofits for space conditioning and CL reduction. Large-scale retrofits have been undertaken for campus HVAC use (*e.g.*, Ball State University in Indiana[116]).

Advantages: HPs use onsite energy to minimize electrical energy requirements for heating, cooling and DHW.

Limitations: GSHP and WSHP initial cost can be high, particularly in retrofit applications. Site-specific factors determine the cost-effectiveness of GSHPs/WSHPs (*e.g.*, soil/bedrock type, access to water). In extreme temperatures HPs energy consumption rises steeply, and efficiency falls off sharply, which can limit reliance upon HPs for space conditioning in some applications.

Strategies: Consider capacity and energy requirements for systems intended to operate in microgrid island mode. Consider use for load reduction, particularly to serve HVAC loads with electricity where CHP is not an economical option, or to complement limited CHP capacity.

4.2 Supply Side: Distributed Generation

This section provides a brief overview of leading distributed generation (DG) technologies, highlighting their respective advantages, limitations and strategies for microgrid applications. The list is not comprehensive. DG definitions vary but generally fall within a 5 kW to 50 MW range of generation capacity. Market forces and public policies drive the recent trend of DG comprising the majority of marginal capacity additions to the grid. Figure B-3 depicts common DG technologies and capacity ranges for microgrid applications.

[116] http://cms.bsu.edu/about/geothermal

Figure B-3: DG Technologies[117]

	DG Technology	Typical Module Size
Nonrenewable	Combined cycle gas turbine	35–400 MW
	Internal combustion engines	5 kW–10 MW
	Combustion turbine	1–250 MW
	Micro-Turbines	35 kW–1 MW
	Fuel cells	1 kW–5 MW
	Stirling engine	2-10kW
	Reciprocating engine	5 kW–50 MW
Renewable	Small hydro	25 kW –10 MW
	Wind turbine	200 W–5 MW
	Solar electric	20 W–100 kW
	Solar thermal	1–80 MW
	Biomass	100 kW–20 MW
	Geothermal	5 kW–100 MW
	Ocean energy	100 kW–1 MW

See Introduction Section 1.2 for a discussion of the inherent risks of the traditional centralized grid with large remote power generation connected via transmission and distribution (T&D) networks to distant customers, compared to the resilience benefits of a more decentralized grid with distributed generation (DG) and other DERs located close to customers in microgrid configurations.[118]

TYPES OF ELECTRIC GENERATORS

The following section from NYSERDA's 2010 report *Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State* (p. 14) provides a typology of DG technologies according to whether or not the device has rotating equipment (*i.e.*, shaft power), as well as the device's ability to operate in grid-independent mode.

<u>Conventional and Non-Conventional Generators</u>

"A major objective of microgrids is to integrate and combine the benefits of both conventional and non-conventional, or renewable and other low-carbon generation technologies such as high-efficiency CHP-based systems. Prospective microgrid DG includes conventional prime movers

[117] NYSERDA 2014, p. 10.
[118] See Lovins and Lovins, *Brittle Power: Energy Strategy for National Security*, 1982, accessible at: http://www.rmi.org/Knowledge-Center/Library/S82-03_BrittlePowerEnergyStrategy

that convert fuel energy into mechanical shaft power, which can then be used to drive a generator to produce electricity. There are many types of prime movers that can be used in microgrid configurations including combustion turbines, micro-turbines, reciprocating engines, steam turbines and sterling engines. Non-conventional forms of DG that produce electric power through means other than mechanical shaft power include fuel cells, photovoltaics and wind turbines."

Induction, Synchronous and Inverter-Based Generators

"There are three types of electric generators – induction, synchronous and inverter-based. 'Synchronous' generators can operate both in parallel and independently of the grid, as they have an autonomously powered 'exciter,' which enables the generator to produce its own reactive power and regulate its own voltage. This contrasts with an 'induction' generator, which cannot operate independently because it relies on the grid for its 'excitation,' meaning the generator is effectively driven by current supplied by the grid and it follows the frequency of this current while operating. If the regional grid goes down, this generator goes down with it. The capability to operate independently of the grid has made synchronous generators an obvious choice for use as backup power in the event of a blackout. This capability also makes these generators appropriate for use in a microgrid configuration. Examples of prime movers that are commonly configured with synchronous generation are combustion turbines and reciprocating engines.

"Inverter-based generation uses a microprocessor-based controller to allow the system to operate in parallel while still synchronizing its power with the grid. Inverter systems convert the direct current (DC) power that is produced by a generator into alternating current (AC) power. The controller can also detect fault conditions on the grid and stop the system from producing power much faster than other forms of generation, thereby contributing insignificant levels of fault current to the grid. Some types of inverters can also quickly and seamlessly switch a DG system into grid-isolated mode, allowing the system to safely provide power to a facility during a grid failure without the risk of back-feed that can jeopardize the safety of work crews trying to fix the fault. This makes inverter based distributed generation particularly attractive to utilities, which are often concerned about the potential for stray current or unintentional islanding with synchronous systems. Examples of inverter-based generation include fuel cells, micro-turbines, photovoltaics and wind turbines."

Emergency, Base Load And Intermittent Generation

The following section from NYSERDA's 2014 report *Microgrids for Critical Facility Resiliency in New York State* (pp. 9–11) categorizes DG technologies by operating modes.

"*Emergency generators* are utilized solely to avoid the negative consequences of power outages. Accordingly, emergency generators rarely run. Diesel generators are the most common emergency power generation source. They can ramp up to full power and respond to varying demands within a few seconds. They can start and run completely unattended. Diesel fuel is more polluting than natural gas and is typically more expensive, so they are less cost-effective where high capacity factor is desired. They are reliable and can easily be designed with black-start capability. Natural gas-fired units are also becoming increasingly more prevalent because of the lesser complexity in operating these units and the recent drop in natural gas fuel costs.

"*Base load generators,* on the other hand, run frequently or continuously—typically only shutting down for maintenance. They tend to be more expensive but more durable than emergency generators. Base load generators also tend to have more strict emissions requirements, more complex permitting processes, and higher maintenance requirements. However, they can also provide additional benefits than emergency generators. Because they operate frequently—even in the absence of a power outage—they can reduce a site's energy purchases from the macrogrid. They may also be able to provide other services to the macrogrid. The revenues and savings created by base load generation are typically anticipated to provide a return on investment that justifies the additional cost. Table 2-1 lists different engine types that may be utilized as base load generation.

"*Intermittent generators* are any generator that may not run continuously due to some external factor. These generators include many renewable sources such as wind and solar. Intermittent generation cannot be relied upon to supply adequate generation capacity when the microgrid is in island-mode, unless the microgrid also incorporates substantial energy storage or other continuous sources.

"The distinction between these types of generators is significant because microgrids that incorporate only emergency generation will only benefit from the reduction in localized power outages, while microgrids that incorporate base load and intermittent generation may be able to monetize other value streams that can aid in cost recovery of microgrid expenses. An entity may invest in the components of a microgrid with emergency generation if they find the cost of owning and maintaining it is lower than the cost of service interruptions. However, when base load generation such as CHP is included, complete microgrid assets can often be justified through energy savings, alone."

DG TECHNOLOGIES IN MICROGRID APPLICATIONS

The following section includes both selections from other reports and the authors' comments on some of the advantages, limitations and potential strategies regarding common DG technologies in microgrid applications.

Standby Backup Generators

Overview: The primary energy assurance strategy for most critical facilities is a backup generator (BUG) that runs on fossil fuel, typically diesel. The BUG is connected to a critical loads circuit and often utilizes an Automatic Transfer Switch (ATS) that disconnects the building from the EPS upon loss of service, while the BUG automatically starts up. The authors categorize BUGs as either emergency or backup generation. Emergency generation enables occupants to exit a building in an emergency by powering life-safety systems such as egress lighting and fire protection systems. Backup generation enables occupants to stay in a building and continue their mission by powering life safety systems as well as mission-critical loads.

Relevant codes and standards include National Fire Protection Association (NFPA) National Fire Code 70, the National Electrical Code (NEC), and NFPA 110[119]. In 2008 the NEC adopted Article 708 Critical Operations Power Systems (COPS) that "provides requirements for the installation, operation, control, and maintenance of electrical equipment and wiring serving designated critical operation areas that must remain operational during a natural or man-made disaster;" and requires that critical facilities maintain a BUG, UPS or fuel cell with the capacity for 72 hours of continuous operation.[120]

CF microgrid planning will often need to address the relationship of retrofit DERs to an existing BUG. RI REG program feasibility study funding can be used in projects that include less than 50% of onsite DG capacity that is natural gas or diesel standby.[121]

Advantages: Diesel BUGs are a mature vernacular technology. They are robust and follow load well, often at relatively good efficiency at partial loads. BUGs provide high energy density and can smooth out intermittent RE generation.

Limitations: BUGs are dependent of fuel supply, which can be vulnerable to disruptions. Standby BUGs depreciate in place, and in practice have displayed availability factor ~0.5 due to poor maintenance and testing practices than can cause problems such as wet stacking that degrade operability.

Strategies: OER could consider allowing microgrid funding applicants to configure existing CFs into BUG-based microgrids, in cases where this configuration enables greater fuel efficiency and reliability, and reduces overall BUG runtime and associated emissions. BUGs can complement intermittent RE DERs by operating in tandem to smooth output, or serving as a standby source of backup power when the DER is no longer able to serve the load. BUGs can complement constant-duty DERs such as CHP or fuel cells, *e.g.*, the DER is base-loaded at full output and the BUG provides swing capacity to follow load swings, as well as provide "black start" power to shut-down DERs in microgrid island mode.

For further reading:

- CT DEEP microgrid grant program, Round 3, Frequently Asked Questions (FAQs), First Installment, Q&A #4 has a well-explained example of multiple scenarios for microgrid configurations comprising only diesel BUGs, and strategies to achieve and calculate reductions in BUG run time, fuel use and emissions[122].

[119] http://www.nfpa.org/codes-and-standards/all-codes-and-standards/list-of-codes-and-standards?mode=code&code=110

[120] http://www.csemag.com/single-article/critical-operations-power-systems-application/0654b6398a77a3e296033ca2909af97c.html

[121] OER's Shauna Beland, personal communication, Jan. 13, 2017.

[122] See PDF pp. 4–6, accessed at: http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/83f46b8356fcf5b885257f0e0062716e?OpenDocument

Base Load Constant Duty Assets: Combined Heat & Power

Overview: "CHP [or "cogeneration"] and CCHP [Combined Cooling, Heat and Power or "trigeneration"] are applications of distributed generation, which involve the sequential or simultaneous production of multiple forms of useful energy (mechanical to drive a generator and thermal for process heat or space conditioning) in a single, integrated system. CHP and CCHP systems typically include specific components – prime mover, generator, heat recovery, absorption cooling, and interconnection – configured into an integrated whole. The type of system is typically identified by the prime mover involved [*e.g*., steam turbines, gas turbines, microturbines, reciprocating engines, and fuel cells, typically fueled by natural gas].

"Steam or hot water produced as a by-product of electric generation by the various prime movers (or possibly a boiler in the case of backpressure steam turbines) can be distributed in pipes to nearby heating loads or run through steam or hot water absorption chillers to produce cold water for cooling. Although the most efficient models are currently at high cost (*i.e.*, double-effect chillers), absorption chillers allow the thermal output of the prime mover to be used across seasons, particularly during the summer when demand for steam or hot water might otherwise decrease. Through the simultaneous use of electricity and thermal energy, CHP systems can reach overall energy efficiencies of as high as 80%. These systems are most efficient if waste heat is used close to the source of production; losses will reduce overall efficiency if the heat must be transferred over long distances, even with heavily insulated pipes."[123]

Although micro-CHP systems exist at generation capacities below 35 kW, most microgrid-scale systems are at least 65‒100 kW and typically larger, ranging up to tens of megawatts. CHP can be well-suited for constant-duty energy production in appropriate applications, although economic feasibility is highly case-specific.

Advantages: CHP can provide significant sustained energy output that is economical and relatively clean. Onsite generation of electricity and thermal energy for heating and cooling is well suited to energizing critical facilities in island mode. In RI National Grid provides significant incentives per kW of installed capacity[124].

Limitations: CHP systems require constant fuel supply. Natural gas pipeline supply must be available at a sufficient pressure and quantity to support the desired installation without utility upgrades; onsite storage capacity is another consideration. Retrofit applications can be costly, particularly where facility HVAC or process systems are not of a type or configuration readily adaptable to make use of CHP byproduct heat. CHP systems are most economical in thermal-load-driven applications (*e.g.*, industrial process heat loads), with byproduct electricity as side benefit. Yet most RI critical facility energy assurance retrofit opportunities are electrical-load-driven with relatively small thermal requirements.

Level 2 campus microgrids tend to be more conducive to economical CHP installations, due to the proximity of facilities with potentially complementary thermal loads. Level 1 single-facility

[123] NYSERDA 2010, pp. 13‒14.
[124] https://www.nationalgridus.com/RI-Business/Energy-Saving-Programs/Cogeneration

microgrids with primarily space conditioning thermal requirements pose challenges for economical CHP installations. The prime mover requires balance-of-system "appurtenances" such as heat exchangers and other equipment to serve seasonal heating loads, plus additional equipment such as absorption chillers to provide cooling energy. Neither heating nor cooling equipment operates year-round in a four-season climate, reducing annual savings and prolonging payback periods. Discarding too much of the byproduct heat can reduce system efficiency, increasing costs and emissions. These factors can constrain the amount of cost-effective power production capacity. The smaller the CHP system, the smaller the savings and the longer the payback period. The business case is made less compelling with lower cost utility-supplied electricity and natural gas.

Note that some smaller CHP applications typically include equipment such as "dump radiators" to shed thermal load when byproduct heat is not required. Although prime mover operating noise can be mitigated by various means (*e.g.*, acoustically-insulated enclosures), dump radiator fans can be noisy and acoustical factors should be considered in installations that are near residential buildings.

CHP experts report that some systems are "colicky" (anecdotally with reciprocating engines and fuel cells), with higher downtime than equivalent systems in other locations. The reasons for this are not always clear, but they can undermine reliability. Some technologies have relatively limited ability follow dynamic loads well in island mode, such as some fuel cells and reciprocating engines.

RI lacks incentives that compensate CHP owners per unit of output (*e.g.*, RECs); CHP is not eligible for net metering.

Strategies: Identify base-load thermal applications. Conducive heating applications can include hospitals, MFH, some wastewater treatment processes, and heated swimming pools; cooling applications can include data centers and refrigeration. Size smaller systems to be base-loaded at constant output during normal "blue sky" operations, and to serve critical loads only during outages while shedding non-essential loads. Larger systems can serve diverse, concentrated loads such as Level 2 campus microgrids. Considerations include siting, permitting, noise, vibration, and the compatibility of building systems and local infrastructure.

<u>CHP Prime Movers: Steam Turbines</u>

"Boilers coupled with steam turbines [STs]are the workhorses of the utility power industry. They can be built to produce up to a thousand or more megawatts each. They can be designed to deliver 250 kW or less depending on the application. They can be designed to burn essentially any combustible fuel. In high capacity factor combined-cycle or CHP applications, they can be extremely efficient and deliver a low life-cycle cost. Steam turbines usually require large capital investments, significant real estate, and dedicated operations personnel. They have long start-up and shutdown periods. They are not appropriate for standby or emergency power generation."[125]

[125] NYSERDA 2014, p. 11.

Advantages: STs offer high energy output. Megawatt-scale systems can participate in ISO-NE energy markets.

Limitations: ST systems can be large, costly, and require custom design and installation.

Strategies: Consider STs for larger applications and systems with appropriate thermal loads, such as Level 2 campus microgrids.

<u>CHP Prime Movers: Natural Gas Turbines</u>

Overview: "Gas turbines [GTs] produce a lot of power in a compact footprint. They are reliable and can easily be designed with black-start capability. They are commonly used in microgrid CHP applications. They can be fired by natural gas, diesel fuel, or both. They range in size from less than 1 MW to more than 100 MW. They can be designed with black start capability. The low inertia and extreme responsiveness of aero derivative engines makes them excellent participants in the frequency and voltage regulation markets." [126]

Natural gas turbines (GTs) are typically used in larger (multi-megawatt) installations. Combined-cycle gas turbines are highly efficient, and can ramp up relatively quickly. They can produce steam and/or high-temperature hot water for CHP.

Advantages: GTs offer high energy output. Megawatt-scale systems can participate in ISO-NE energy markets. Smaller systems can be containerized.

Limitations: GT systems can be large, costly, and noisy, with significant natural gas supply requirements.

Strategies: Consider GTs for larger applications and systems with appropriate thermal loads, such as Level 2 campus microgrids.

<u>CHP Prime Movers: Microturbines</u>

Overview: "Microturbines are small packaged gas turbine power generation units. They can provide on-site electrical power for standby applications, peak shaving, or base loading. Microturbines may generate power while synchronized with an electrical utility or isolated from it. The microturbine system is sold as a package consisting of a turbine engine, solid-state power electronics, a fuel system, and an indoor/outdoor-rated enclosure. Individual microturbines typically produce 5 kW to 100 kW each. They can be combined for larger applications."[127]

Smaller microturbine (MT) units (65–100 kW+) with as few as one moving part run on natural gas as the primary fuel; some models can burn other fuels also. The modular design is readily scalable. Generally they have a relatively higher heat-to-power output ratio and higher temperature byproduct heat than other small prime movers such as reciprocating engines, but

[126] NYSERDA 2014, p. 11.
[127] NYSERDA 2014, p. 11.

lower-temperature recoverable heat than larger GTs.

Advantages: Compact, light, low emissions, modular scalable installations, can be containerized.

Limitations: Relatively high capital cost and O&M costs compared to other small prime movers (*e.g.*, reciprocating engines). Often require a natural gas compressor that adds cost, complexity and another point of failure.

Strategies: Consider for appropriate thermal applications.

CHP Prime Movers: Reciprocating Engines

Overview: "Reciprocating engines can be fueled by natural gas, diesel, and biofuels. Each of these variants will have some impact on the performance of the engine. Natural gas burns cleaner, and is often less expensive than distillate fuels. Maintenance costs tend to be lower than with liquid-fuel engines. But as a compressible fuel natural gas results in an engine that is slower to respond to load changes. Diesel engines will therefore tend to be more responsive under quickly changing load conditions. Natural gas engines can be used to produce low-cost base-load or supplementary power. It can have a very high efficiency and low life-cycle cost and low carbon footprint in CHP applications. Fuel is usually delivered by underground pipeline. Reciprocating gas engines are not ideally suited to be the *only* engine supporting a microgrid. With thoughtful use of digital controls, they can however be coupled with other power generation very cost-effectively. Some manufacturers offer dual-fuel gas/diesel reciprocating engines. Reciprocating engines can also be made to run on biodiesel or biofuels."[128]

Reciprocating engines (recips) are essentially the same design as a large internal combustion engine in a truck. Lower-temperature byproduct heat can be a good fit for space heating, particularly in buildings with hydronic heating.

Advantages: Recips are a mature vernacular technology, among the most economical prime movers with relatively low initial cost and moderate O&M and other life-cycle costs. This familiar technology can be reassuring to microgrid project stakeholders who are leery of unfamiliar technologies being installed in their facility. Recips can have good load following ability and partial load efficiency, but natural gas recips are less able to follow rapid load changes. Small-scale modular 60–100 kW Commercial Off-The-Shelf (COTS) systems are available, some with integrated inverter / controls; modularity facilitates scalability. Larger Megawatt-plus units are also available. Can be containerized, which can mitigate sound and vibration.

Limitations: Relatively higher emissions and noise, requires cooling and exhaust stack, provide lower-temperature heat. Lean-burn natural gas recips, base loaded for efficiency, can have relatively slow ramp rates and don't follow large load changes well on their own in island mode. Some installations are "colicky" with relatively high downtime, it is not always clear why and uptime can be hard to predict accurately in any given installation.

[128] NYSERDA 2014, p. 11.

Strategies: Consider for smaller-scale CHP applications with lower-temperature thermal applications such as space heating and cooling.

CHP Prime Movers: Fuel Cells

Overview: Fuel cells (FCs) are electrochemical devices with various chemistries and designs, typically with high fuel-to-energy conversion efficiency and negligible emissions; in most types the most tangible byproduct is hot distilled water. FCs typically run on hydrogen, which is usually "reformed" from natural gas onsite. They are relatively quiet and produce high-quality power suitable for sensitive loads such as servers and other electronics. Different FC types produce a range of byproduct hot water temperatures for CHP applications. FCs are very costly but some installations are eligible for a 30% Federal Investment Tax Credit (FITC). In RI, FCs that run on biomass fuel or landfill methane are eligible for net metering, virtual net metering (VNM), and Renewable Energy Standard (RES) feasibility study funding. FCs technologies continue to evolve, and the mobile and stationary applications markets continue to grow despite continued lack of profitability among publicly-held manufacturers.[129]

Advantages: High efficiency and power quality, very low emissions, potentially low noise. FCs have the best power-to-heat output ratio (*i.e.*, most power, least heat) for electrically-driven applications of any prime mover. Some designs have good uptime and high reliability factors.

Limitations: Very high capital cost, needs natural gas reformer. Some FC CHP installations have demonstrated less-than-desired reliability for island mode operations.[130] Only Proton Exchange Membrane (PEM) FC types follow dynamic loads well in island mode without supplemental systems that enable rapid ramp rates (*e.g.*, capacitors, BUGs); other designs vary output by modulating gas supply up or down.

Strategies: Consider base-loaded, high power quality applications, *e.g.*, server farms, etc.

For further reading:

The following resources are focused on fuel cells for resilience.

- Resilient Power Project, *Resilient Power Case Study Series: Fuel Cells for Resilient Power*[131] is a brief primer on FC applications for grid-independent operations.

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[129] https://www.greentechmedia.com/articles/read/Fuel-Cells-2016-Within-Striking-Distance-of-Profitability

[130] An anecdotal example: In Glastonbury, CT a 200 kW United Technologies Corporation FC CHP installation supplied a Whole Foods grocery store with power and refrigeration during normal operations; during the 2011 Two Storms outages lasting more than one week each event in some parts of town, that grocery store was among the only commercial facilities operating in town and provided valuable community support. An almost identical installation at another CT grocery store was out of service during one of those outages due to problems in "balance of system" components (*e.g.*, pumps).

[131] http://www.cleanegroup.org/ceg-resources/resource/resilient-power-case-study-series-fuel-cells-for-resilient-power/

Solar Photovoltaic Power

Overview: Solar photovoltaic (PV) power benefits from technological progress and strong market and policy support, factors that have reduced costs 10–15% annually in recent years. Panel mounting techniques and technologies are listed from least to greatest average cost as follows: flat-rooftop ballasted; flat- or pitched-rooftop anchored; ground mount; and parking canopy.

PV generates DC power and requires and inverter to supply AC power to facilities. Most grid-tied inverters are configured to disconnect PV from both the EPS and the facility loads upon loss of grid power, as per IEEE 1547 and UL 1741 standards. Islandable systems require appropriate inverters, plus either battery energy storage or a tandem generator to smooth out the PV's intermittent output, to serve loads in grid-independent inverters. COTS controls packages enable PV+BUG "hybrid" microgrid systems, where PV is the prime generator, paired with diesel BUGs that vary their output to smooth out PV production; in this case the diesel fuel serves as the energy storage.[132] PV can be paired with battery energy storage (BES) to smooth output and shift energy supply to different time periods. It is technically possible to retrofit existing PV systems with equipment to enable grid-independent operations.

Federal incentives include 30% FITC and Modified Accelerated Cost Recovery System (MACRS) depreciation schedule. RI net metered PV installations up to 10 MW are behind one customer's meter. RI's REG feed-in tariff (FIT) provides stronger economic support for PV installations, but REG-funded PV is connected directly to the EPS with a production meter, so a switch would be required to enable the PV to serve facility loads during an outage; evidently this is an untested or unprecedented configuration within the REG program. Eligible RI public sector and MFH organizations can use community remote virtual net metering (VNM) to allocate per-kWh credits across multiple eligible accounts from PV installations up to 30 MW or more.

Advantages: Clean, quiet, economical power readily sited close to load almost anywhere (with conducive site conditions), with no fuel cost and minimal O&M costs. Significant utility cost savings are possible under normal "blue sky" conditions. Robust competitive marketplace for increasingly vernacular technology. Strong Federal and state policy and incentive support. Innovative financing and competitive business models with no up-front cost include Power Purchase Agreements (PPAs), RIIB C-PACE financing, and (virtual) net metering.

Limitations: Intermittent resource with low power density mean that a relatively large physical footprint is needed to serve facility-scale loads. Site factors constrain cost-effectiveness at many sites (*e.g.*, roof size / type / age; shading). Standard PV grid-tied inverters (*e.g.*, in PPAs) are configured to disconnect during outages; modifications required for grid-independent operations. PV requires battery energy storage (BES) for 24/7 applications; reliance on PV for grid-independent operation would require PV capacity to serve loads plus additional capacity to simultaneously charge BES to serve loads later (at night) in island mode. High capital costs, but falling rapidly. Public sector organizations can't use tax credits or C-PACE, so PPAs and alternative financing are important options. Hardening installations against severe weather (*e.g.*,

[132] For example, see: http://www.sma.de/en/products/monitoring-control/sma-fuel-save-controller.html

high wind speeds) can be costly.

Strategies: Identify sites for large arrays (*e.g.*, large flat newer roofs, parking areas, open land, capped landfills) that serve 1+ CF during outages. PV+BES can be good modular option, if necessary in combination with BUGs or other DG. OER could consider developing a standardized modular retrofit kit for adding BES, inverters and controls to existing PV systems that can't currently island. Size costly PV + BES capacity for most critical subset of loads (*e.g.*, IT/telecom/radios, emergency shelter lighting, device charging). Consider options for pairing with other onsite generation (*e.g.*, CHP, BUGs); note this can increase controls complexity and cost. Negotiate new and retrofit islanding capability with PPA providers, including BES capacity as part of PPA.

For further reading:

The following resources are focused on PV+BES for resilience.

- Resilient Power Project, *Solar+Storage 101* is an excellent primer on PV+BES systems design and procurement applications, options and strategies, including different inverter types and configurations for grid-independent operations.[133]
- NY Solar DG Smart DG Hub has excellent resources regarding solar plus storage for resilience (including retrofitting existing PV with BES), particularly in the "Solar + Storage Resources" section: see *Resilient Solar PV Systems Hardware Fact Sheet, Economics & Finance of Solar + Storage Fact Sheet, Solar+Storage and Microgrid Communications Fact Sheet, Solar and Storage Cost Survey,* and *Solar+Storage Retrofit Guidelines*. [134]

Energy Storage

Overview: There are numerous energy storage (ES) technologies; this report will focus on battery energy storage (BES). Battery types and chemistries vary; mature lead-acid batteries and still-evolving lithium ion technologies currently dominate microgrid BES applications. There is a great deal of innovation and research & development (R&D) occurring in energy storage; other battery technologies exist and are also maturing. For example, flow batteries use pairs of liquid electrolytes that can be stored in separate tanks in desired quantities and pumped through the battery cell or stack to charge or discharge, enabling a broad range of storage capacities and performance characteristics.

The following graphics from the Massachusetts Energy Storage Initiative 2016 report State of Charge depict energy storage technology types and parameters.

[133] http://www.cleanegroup.org/ceg-resources/resource/solar-storage-101-an-introductory-guide-to-resilient-solar-power-systems/

[134] http://www.cuny.edu/about/resources/sustainability/SmartDGHubEmergencyPower.html and https://nysolarmap.com/resources/reports/ and particularly https://nysolarmap.com/resources/reports/solarplusstorage/

Figure B-4: Classification of Energy Storage technologies (ESS)[135]

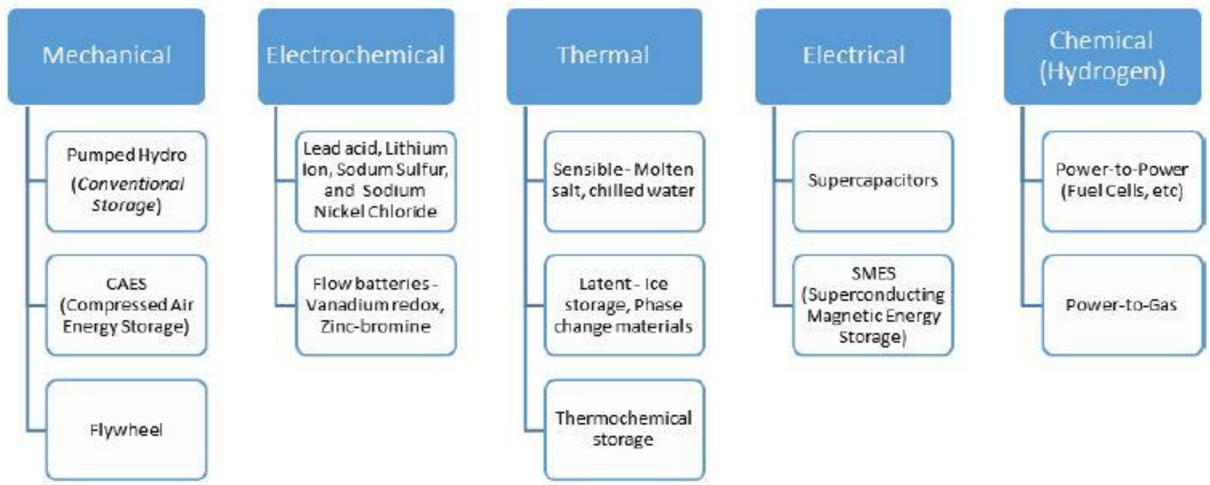


Figure 4: Classification of Energy Storage Technologies

Table B-5: Parameters for Select Energy Storage Systems (ESS)[136]

Energy Storage System Attributes	Lead Acid	Li –Ion	NaS	Flow Batteries	Flywheel	CAES	Pumped Hydro
Round Trip Energy Efficiency (DC-DC)	70-85%	85-95%	70-80%	60-75%	60-80%	50-65%	70-80%
Range of Discharge Duration	2-6 Hours	.25–4+ Hours	6-8 Hours	4-12 Hours	.25-4 Hours	4-10 Hours	6-20 Hours
C Rate	C2 – C6	4C – C6	C6-C8	C4-C12	4C-C4	N.A.	N.A.
Cost range per energy available in each full discharge ($/kWh)	100-300	400-1000	400-600	500-1000	1000-4000	>150	50-150
Development & Construction Period	6 months - 1 year	6 months - 1 year	6 months - 1.5 year	6 months - 1 year	1-2 years	3-10 years	5-15 years
Operating Cost	High	Low	Moderate	Moderate	Low	Moderate	Low
Estimated Space Required	Large	Small	Moderate	Moderate	Small	Moderate	Large
Cycle life: # of discharges of stored energy	500-2000	2000 -6000+	3000-5000	5000 - 8000+	100,000	10,000+	10,000+
Maturity of Technology	Mature	Commercial	Commercial	Early - moderate	Early - moderate	Moderate	Mature

Table 1-1: Parameters for Select Energy Storage Systems (ESS)[13]

[135] *State of Charge: Massachusetts Energy Storage Initiative Study*, 2016, p. 3.
[136] *State of Charge: Massachusetts Energy Storage Initiative Study*, 2016, p. 7.

Thermal Energy Storage (TES) systems can store thermal or electrical energy as thermal energy for later use (*e.g.*, electric hot water heaters or ice makers that produce chilled water), which is potentially valuable for critical facility and microgrid energy management. Pilot applications of "virtual" aggregations of remotely-controlled electric hot water heaters have demonstrated grid support benefits by providing resistive load and demand response capacities.

Applications: Batteries provide a spectrum of services from power-intensive to energy-intensive applications. Generally, a given BES system operates optimally at either a power-intensive or an energy-intensive application, but most technologies are not well-suited to perform both types of services without shortening their service life. ES technologies can be integrated into composite installations, with one type (*e.g.*, a flywheel) for power-intensive operations (*e.g.*, rapid-cycle charging and discharging to smooth out intermittent renewable generation), plus another type (*e.g.*, lead-acid or Li-ion BES) to provide energy-intensive applications (*e.g.*, sustained discharge for peak shaving or grid-independent operations).

The following graphics from ABB depict the spectrum of power- to energy-intensive applications, which ABB refers to as the "7S applications".

Figure B-5: Energy Storage 7S Applications

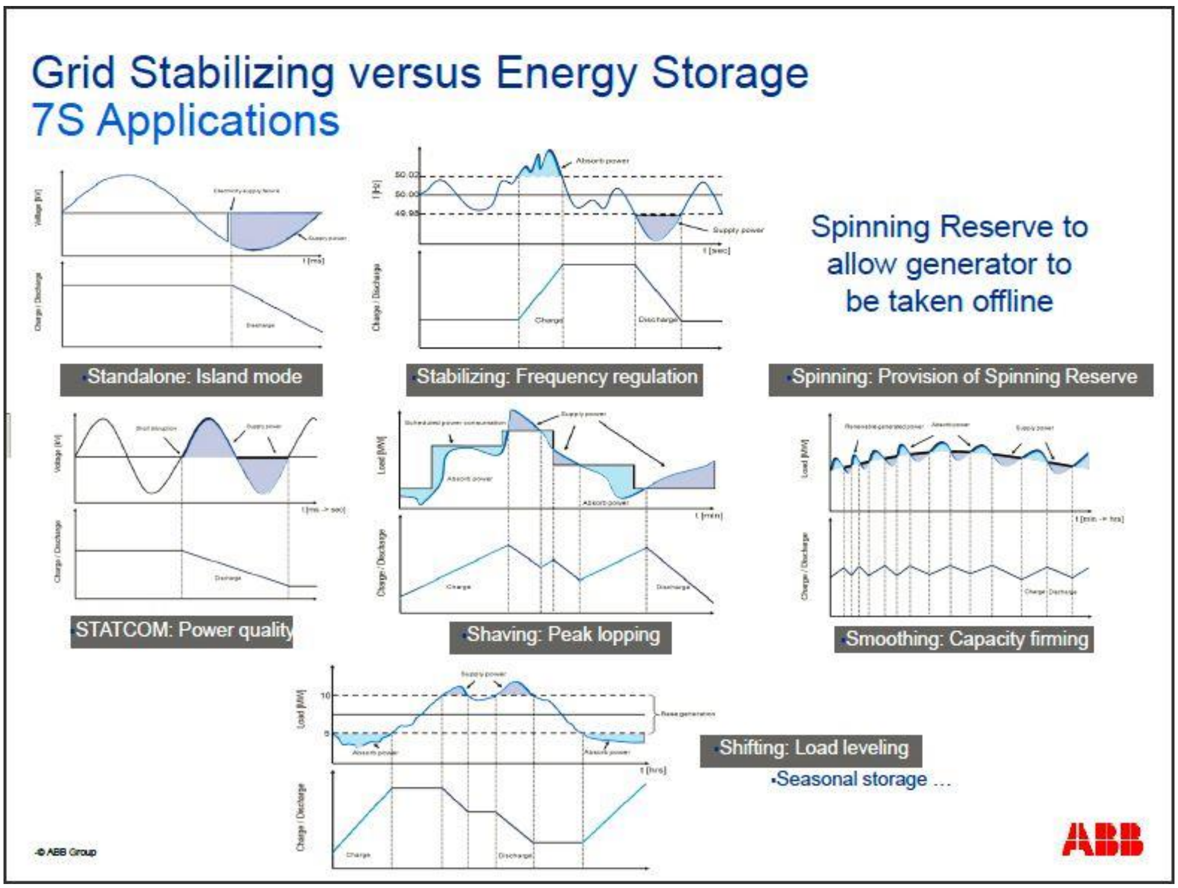


Image courtesy of William Galton, ABB.

Table B-6: Energy Storage 7S Applications for Microgrids

Grid Stabilizing versus Energy Storage

- The 7S Applications in Microgrids

	Application	Time Frame	Energy	Power
1	Standalone (diesel off)	millisec	low	high
2	Stabilize (f,V support)	seconds	low	high
3	Statcom (Power Quality)	seconds	zero	high
4	Spinning Reserve	seconds/ minutes	medium	high
5	Smoothing (Renewable Energy)	minutes	medium	medium
6	Shaping (Peak Lopping)	minutes/hours	medium	Low
7	Shifting (Load levelling)	hours	high	low

Image courtesy of William Galton, ABB.

Applications include:

- Bridging / buffer / Uninterruptible Power Supply (UPS): Batteries can provide instantly-available energy to serve critical loads during grid outages until either service is restored or back up generation comes online. USDOE Energy Storage Program Manager Dr. Imre Gyuk once observed that "the most valuable energy storage is the first 15 minutes" during an outage.
- Renewable energy support: BES can support intermittent renewable energy (RE) DERs by smoothing out short-term output fluctuations (generally a power-intensive application), and "arbitrage" shifting RE output by charging during less valuable or costly times of day and discharging during more valuable or remunerative times of day (generally an energy-intensive application).
- EPS / microgrid electricity distribution infrastructure support: ES can provide "ancillary services" such as frequency regulation to the macro- or microgrid to maintain power quality and voltage stability. In some areas markets exist to compensate BES for these services, although in ISO-NE territory the minimum BES system size to participate in those markets is 1 MW.
- EPS / microgrid economic support: BES can provide many of the DER benefits for grid support, such as congestion relief, service restoration support, peak shaving, demand response, and other ancillary services that can potentially provide revenue for microgrids.

BES economics remain challenging despite relatively rapid technological innovation and maturation that is reducing costs by roughly 5%–15% annually in recent years. It is difficult to predict the economics and service of even identical BES technologies in different applications and operating profile sand conditions. Customer demand charge reduction opportunities that provide a reasonable payback period remain uncommon for current BES technologies. It can be difficult to combine more than one source of monetizable value. One BES system developer stated in an interview that after years of business development effort in the Northeast, he concluded that "there are almost no economical single-application business models that justify energy storage investments in New England—yet…" Conditions are improving and there are good opportunities for policy and programmatic support.

OER could consider potential developments and synergies with developments in electric vehicles (EVs). Many analysts think that EVs could deploy greater BES capacity, sooner, than stationary applications—and note that EVs are stationary much of the time. Potentially EVs can serve as mobile BES systems that can provide ES services to microgrids while parked, via electric vehicle-to-building (EV2B) and vehicle-to-grid (EV2G) applications. Critical facility microgrids can charge EVs to support transportation-dependent critical missions. The secondary market for repurposed "used" EV batteries (commonly removed from EV service at roughly ~80% of original capacity) could be a growing source of lower-cost Li-ion and other BES types for stationary applications such as community energy storage.

Advantages: Microgrid and EPS support applications can potentially lower risk and increase revenue. Many ES technologies are modular, scalable, and potentially can be aggregated "virtually" with controls and communications to realize greater capacity and potential revenue. ES can firm up RE output, enabling island mode CL support. ES requires less infrastructure (*e.g.*, pipelines, water) than other DG.

Limitations: High capital (and potentially maintenance) costs, complexity, market immaturity, low familiarity with rapidly-maturing technologies. Difficulty "stacking" multiple potential value streams economically. Many ES technologies are best suited for either power- or energy-intensive applications, but generally not both. Safety chemistry risks due to BES chemistry, and lack of clarity in building codes for newer BES types, can complicate permitting and siting and increase installation cost.

Strategies: Look for peak shaving and demand charge reduction opportunities. RI OER could support virtual or aggregated microgrids and power plants to enable participation in ISO-NE ancillary services markets, which have a 1 MW capacity threshold. Massachusetts recently determined that EDCs can own storage, including National Grid. EDC- or third-party-owned utility-scale BES for EPS ancillary services and grid support (*e.g.*, at the substation level) could be configured to serve 1+ CFs.

Identify and support EV market interactions and synergies, *e.g.*, EV2B bidirectional charging kits that enable plug-in EVs to provide power to residence and critical facilities. Currently only 12V adapter kits are available for minimal plug loads support; in Japan suppliers such as Nissan offer a kit for EV2B, which is not yet available in the U.S. Analysts note that DC fast chargers (*e.g.*, for EVs) comprise a "peaky" and challenging load set for EDC distribution system managers.

For further reading:

- Energy Storage Association website[137], see "Energy Storage" section for overview of ES markets and technologies as well as policy recommendations.
- Resilient Power Project, *Energy Storage and Electricity Markets*, 2015[138]. This excellent primer cover ES technologies with a focus on PV+BES for energy assurance.
- *State of Charge: Massachusetts Energy Storage Initiative Study*, 2016.[139] This report includes concise ES technology overview as well as recommended polices.

Wind Power

Overview: Wind power includes large capacity, tall offshore and onshore wind turbines (WTs), as well as smaller ground-mounted and building-integrated WTs (BIWTs). WTs are a mature, increasingly cost-competitive DG technology in applicable areas, although conducive wind resources are highly site-specific at ground level (wind conditions improve with altitude) and not as ubiquitous as solar insolation. Sustained winds are more prevalent at night and along the coast; offshore wind conditions are most conducive. Smaller, building-integrated BIWT are less mature and not widely employed, with many types of varied efficacy and a mixed reputation in the marketplace. Large WTs can provide relatively high power density when operating. The state has better wind potential than many states, but coastal siting faces many political and administrative challenges, including common Not In My Backyard (NIMBY) public push-back against taller WTs in particular due to view shed impacts, flicker, bird kill and other real and perceived downsides. RI has deployed the nation's first offshore wind farm comprising 5 WTs off of Block Island, and 2016 saw installations including 10 new land based WTs in Coventry.[140]

Advantages: WTs are an increasingly competitive RE DG option, thanks in part to Federal and state policy support. Larger high-capacity systems can generate significant amounts of clean electricity.

Limitations: Like other intermittent RE, WTs require ES support for higher-reliability microgrid applications and to boost economic performance; often the best output is at night during periods of sustained winds but low grid demand. The wind resource is site-specific, especially onshore. Siting constraints mitigate the market potential of larger WTs.

Strategies: Consider WTs for appropriate locations, particularly larger coastal and island locations as well as conducive sites farther inland. Evaluate BIWTs carefully for efficacy.

[137] http://energystorage.org/energy-storage
[138] http://www.cleanegroup.org/ceg-resources/resource/solar-storage-101-an-introductory-guide-to-resilient-solar-power-systems/
[139] http://www.mass.gov/eea/docs/doer/state-of-charge-report.pdf
[140] OER's Danny Musher, personal communications, Jan. 24, 2017. In 2017 the DPUC considered supporting development of a microgrid on Block Island using Blockchain technology.

Hydropower

Overview: Hydropower is a mature technology, yet with ongoing innovation in small hydro (up to 10 MW) and "microhydro" (up to 100 kW). Local-scale hydropower is highly site-specific. Environmental trade-offs are trending towards removal of dams in the Northeast rather than adding hydropower to them. Some opportunities remain. Technologies exist for retrofitting small systems up to 100 kW into gravity-fed pipes[141] and urban or in-building piping[142]. Some small-scale hydro applications could be microgrid-configurable but it does not represent a common option.

Advantages: In conducive applications, hydro could serve as a baseload or intermittent RE resource. Urban and facility-scale retrofit opportunities are not widely appreciated or understood.

Limitations: Conducive locations are highly site-specific, and can be subject to fluctuations in output due to seasonal factors or other operating parameters. Siting, permitting and environmental constraints can be significant.

Strategies: Explore modifying existing systems to enable grid-independent operation. Consider small-scale, low-impact opportunities. Microhydro and in-facility retrofit energy assurance opportunities could be investigated within water and wastewater critical infrastructure.

4.3 Microgrid interconnection, controls, and operational considerations

This section discusses microgrid's core technical and operational considerations, driving factors in microgrid design and configuration of its relationship with the larger grid to which it is connected. Put colloquially: this is the hard part of microgrid design and operation, and controls are the special sauce that enables safe and economical operation.

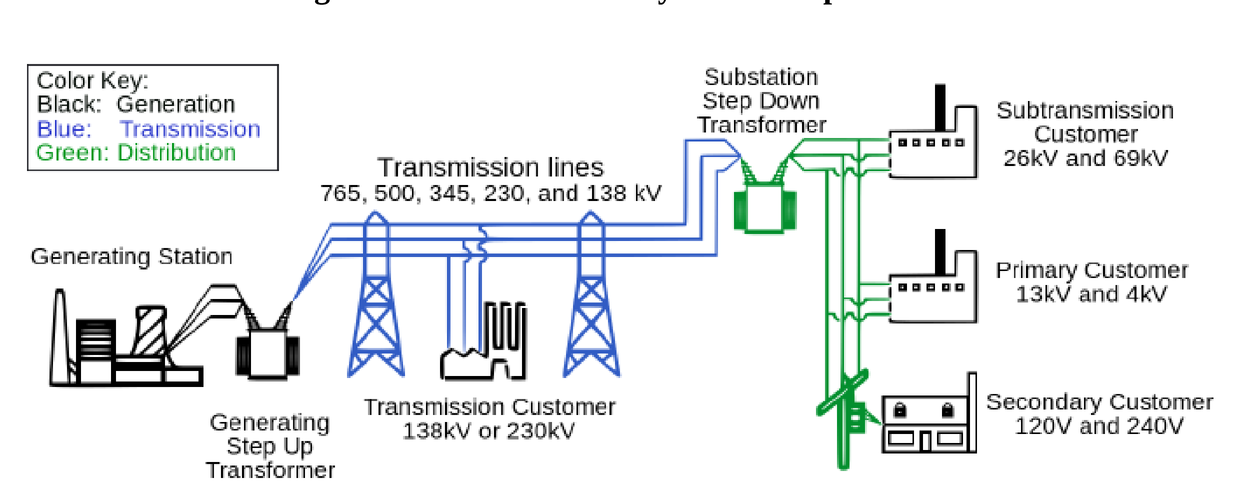
The authors intend that this survey of these issues is accessible to technically literate non-engineers. We discuss many aspects of a microgrid's relationship to the macrogrid, starting with similarities in construction and operation. We discuss meters, interconnection of the microgrid to the macrogrid at the point of common coupling, and IEEE 1547 standards that define requirements for safe operation of microgrids and their DERs in relation to the macrogrid. We review technical considerations for microgrid operation in both grid-connected and island modes, and transitions between the two. We highlight the considerations for microgrid interconnection to different types of EPS distribution circuits in rural, suburban and urban areas. We explore microgrid control technologies and techniques to address these challenges and requirements. The authors reference and quote at length from state microgrid reports and other resources.

[141] For example, see: http://rentricity.com/
[142] For example, see: http://www.ijsgce.com/uploadfile/2015/0929/20150929103416700.pdf

ELECTRICITY DISTRIBUTION INFRASTRUCTURE IN GRIDS AND MICROGRIDS

Figure B-6 shows the major components of the "macrogrid". The EPS is defined as the medium- to lower-voltage (at or below 69 kV) distribution portion of the network, shown in green.

Figure B-6: Electric Grid Systems Components[143]



The EDC owns and manages this segment connecting higher-voltage transmission with low-voltage customers; the EPS stops at the customer meter. EPS infrastructure is akin to that contained within (some) microgrids, albeit on a smaller scale and often at lower voltages. Both the EDC and microgrid owners have similar tasks and objectives for electric power generation and distribution in a safe and reliable manner, with comparable tools and equivalent concerns about system resilience in the face of faults, accidents, and insults such as severe weather.

Above-ground or overhead EPS and microgrid distribution infrastructure hardening techniques and technologies are similar. Sensors, breakers, reclosers, sectionalizers, relays and other devices help monitor grid operations and clear and isolate faults; many can be used in microgrids as well. Vegetation management (tree trimming) reduces risks. Poles can be strengthened against wind and flooding; wires can be buried and floodproofed; substations and transformers can be elevated above flood levels. But hardening the entire system would be very expensive, and localized equipment damage could still cause widespread outages.

"Undergrounding electric system wires is extremely costly. Recent reports by Florida, North Carolina, Oklahoma, Virginia and Maryland did not find undergrounding wires was not cost efficient, and did not recommend it as an option to respond to recent system-wide grid power outages caused by severe weather. A recent Edison Electric Institute [EEI] study found the cost for overhead lines was between $136,000 to $197,000 per mile, and the cost for undergrounding

[143] NJBPU 2016, p. 45.

wires was at a range of $409,000 to $559,000 per mile without the same level of benefits."[144] EEI estimated that undergrounding urban power lines could cost over $2 million per mile.[145]

Microgrids are a cost-effective approach to enhancing EPS and community resiliency without extensive and expensive EPS hardening; plus microgrids can provide a host of benefits that buried wires cannot. Yet microgrids themselves might want to harden their power infrastructure. One relatively low-cost alternative to undergrounding is to modify existing EPS infrastructure to form a microgrid (where allowable and applicable) with reclosers, switches, etc. to isolate segments of the EPS for microgrid use. These segments could be listed as priority locations for service restoration by the EDC in the event of a disruption, provided that the microgrid's critical mission could continue with other resources (*e.g.*, BUGs) while repairs were made.

<u>Meters</u>

Customer meters are the most basic form of facility or DER interface with EPS or microgrid distribution infrastructure. Meters touch on several aspects of microgrid planning and design.

Energy use data. RI customers can download 2 or more years of usage history for each meter. Some meters can provide 15 minute interval data for electricity (or natural gas) usage, which is very valuable for accurate planning of DER capacity. Some Commercial & Industrial (C&I) meters in RI can be used to provide interval data, but not residential meters.

DG program participation. Many DG incentive programs such as net metering are allocated on a per-meter basis.

Interconnection. Applications are generally conducted associated with a particular meter. Renewable resources that receive the REG FIT are connected directly to the EPS with a dedicated production meter, rather than being installed behind the host customer's meter as would be the case in a net metered installation. A switch would be required to disconnect a REG FIT funded DER to enable island mode power supply to the host facility, *i.e.*, to disconnect the DER from the EPS and connect it to the host facility's electricity distribution wiring.

Master metering vs. *submetering*. Microgrid planning can be simplified in some respects if a facility has one meter. For example, if a multifamily housing (MFH) facility has individually-metered apartments, it could be dissuasively complex to serve those accounts with onsite DERs; each customer would have to develop a separate agreement with the power provider, which in turn might have to become a registered power provider in order to sell power to third parties. In 2016 Rhode Island determined that master metering would no longer be allowed in new MFH construction; apparently existing master metered facilities will be grandfathered.

Advanced Metering Infrastructure (AMI). AMI or "smart meters" provides two-way communications between the EDC and the meter. Potentially AMI could also be used to

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[144] NJBPU 2016, pp. 33–34, and citing EEI: http://www.eei.org/issuesandpolicy/electricreliability/undergrounding/documents/undergroundreport.pdf
[145] http://www.nj.com/business/index.ssf/2012/11/should_utility_electric_lines.html

segregate customers from a distribution circuit by remote control, which could be used to shed load within a multi-facility microgrid or if EPS circuits were adapted for microgrid use. In Rhode Island the EDC has wireless Automated Meter Reading (AMR) technology enabling wireless meters reading. The EDC has not yet deployed AMI.

Interconnection / Point of Common Coupling

A microgrid's Point of Common Coupling (PCC) is the physical and electrical interface with EPS. This equipment is intended to enable safe transition between grid-connected and grid-independent modes, and safe operation in either mode, for both the microgrid and the macrogrid. A PCC should facilitate the following microgrid functions:

- Enable intentional islanding from, and re-connection to, the EPS
- Prevent unintentional islanding from, or re-connection to, the EPS
- Import electricity from the grid
- Prevent unintentional back-feeding of microgrid power to the macrogrid
- Export power from the microgrid to the macrogrid (if that is a design feature)
- Prevent electrical faults on either side of the PCC resulting from differences in power quality and stability between the microgrid and the macrogrid

Bidirectional PCC configurations are most common, to enable power imports and exports. Some PCC types employ an import-only strategy. One design employs series active rectifiers: one on the EPS side to convert grid power from AC to DC and feed it to a DC bus, with another on the microgrid side of the bus that convert DC back to AC to serve microgrid loads. This design imposes a modest penalty of conversion losses, but minimizes the risk of backfeeding power to the EPS.

Interconnection: IEEE Standards and Safety Considerations

"The Institute for Electrical and Electronic Engineers (IEEE) has several codes and guides related to microgrids and DER operation to and within the grid. Specifically IEEE 1547 series of standards addresses the interconnection of DER to the distribution grid. IEEE 1547.4 addresses the standard related to islanding of DER microgrids. These standards are in the process of being upgraded and expanded given the recent interest in enhancing the development of microgrids, especially advanced microgrids.... Another related IEEE standard is the interoperability standards at IEEE 2030 Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power Systems and End-Use Applications and Loads. The guide provides standard in understanding and defining smart grid interoperability of the electric power system with end-use applications and loads. Smart grid is a key in expanding and implementing DER advanced microgrids and IEEE 2030 is a key standard to expanding and implementing Smart Grid."[146]

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[146] http://www.nrel.gov/docs/fy15osti/63157.pdf , cited in NJBPU 2016, pp. 35–36.

The NYSERDA 2014 report *Microgrids for Critical Facility Resiliency in New York State*, Section 5.2 General Issues Affecting Microgrid Development, provides an excellent and detailed discussion of the many technical issues concerning microgrid islanding and reconnection. The authors quote from this section at length below, and refer the reader to the rest of the report sections described below.

"The IEEE is expected to revise its 1547 standards, which will incorporate microgrid configurations, by 2018.[147] IEEE 1547.4 and 1547.6 are specifically designed to address issues associated with the interconnection of microgrids to the electric grid.[148] Like distribution generation, microgrids are required to meet several technical standards prior to interconnecting with the electric grid, including those associated with (1) overcurrent protection; (2) synchronization; (3) voltage control and power control; (4) metering and monitoring and (5) IEEE 1547 compliance."[149]

"Different sets of technical requirements will affect a microgrid in grid-connected mode and in islanded mode. In grid-connected mode, all of the distributed resources in a microgrid will have to meet the requirements that apply to grid-connected distributed generation. Such requirements normally cover several topics, including impacts on the following:

- Utility voltage and voltage regulating equipment.
- Overcurrent protection.
- Effective grounding.
- Islanding prevention.
- Harmonics.
- Voltage flicker.
- Load rejection overvoltage.

"A different set of technical requirements will impact the microgrid when it transitions into islanded mode. With traditional distributed generation, islanding is something to be avoided, but with a microgrid, islanding is a key benefit for resiliency and reliability. Many of these integration issues will also apply when the microgrid is operating in standalone (islanded) mode, but the circuitry, control modes, and power flows may be quite different than when grid connected. Microgrids must meet utility standards when interconnected with the utility grid and when reconnecting with the grid. When operating in standalone mode, the microgrid may or may not need to follow utility standards, depending on who owns various parts of the microgrid infrastructure. Regardless of ownership and ruling guidelines, the technical issues are the same; all parties want safe, controllable electricity distribution within the microgrid that supplies suitable voltage and frequency to loads.

[147] NYSERDA 2014, p. 46.
[148] NYSERDA 2014, p. 44.
[149] NYSERDA 2014, p. 44.

"In standalone mode, several additional issues arise:

- Voltage control.
- Frequency control.
- Matching generation with load.
- Synchronization.
- Black start capability.

[NYSERDA 2014] "Section 5.1 details a series of general issues that affect microgrid interconnection in any environment, such as overcurrent protection, synchronization, voltage and power control, metering and monitoring, supplying critical infrastructure, and black starting. Sections 5.2 and 5.3 consider several different design typologies for microgrid distribution networks (*e.g.*, a campus style microgrid *vs*. a microgrid operating in a grid network), each of which are most likely to be found in different environments (rural, suburban, and urban) with characteristics that also impact the microgrid."[150]

[NYSERDA 2014] Section 5.2.2 Safety (pp. 49–50) is a brief description of safety issues to be managed in microgrids, including backfeeds and downed conductors; unintentional islanding; maintaining electrical boundaries; communications and control; and grounding compatibility.

Synchronization of microgrid and EPS

[NYSERDA 2014] Section 5.2.3 Synchronization (pp. 50–51) is very important, a central issue in microgrid design and operation. Note the three strategies described; open transition is the simplest and safest.

"When reconnecting a microgrid to a utility system, an important consideration is synchronization of the microgrid to the utility system to avoid disturbances upon reconnection. Synchronization refers to matching the speed and frequency of power on the microgrid's distribution system to the speed and frequency of power on the utility's distribution system, so that these can seamlessly mesh once reconnected. Proper synchronization will help protect both utility-side and microgrid-side equipment. For synchronization, the voltage, frequency, and phase angle must be within certain bands to minimize connection transients. From most sophisticated to least sophisticated, options to synchronize include:

- Active synchronization—If the microgrid voltage and frequency can be controlled sufficiently, then the microgrid controller can align the voltage and frequency to the utility power system and then reclose.
- Sync check—Reconnection can be blocked by a sync-check relay. The microgrid controller can initiate reclose, and the system should reconnect when the two systems are within synchronization tolerances. If the systems are badly out of sync, reconnection may not be possible.

[150] NYSERDA 2014,, pp. 44–45.

- Open transition—Disturbances are avoided by de-energizing the microgrid and then reconnecting utility power system. Once reconnected, the distributed generation can be restarted if desired."[151]

[NYSERDA 2014] Section 5.2.4 Voltage Control and Power Control (pp. 51–53) is also vital.

"Each of the loads in a microgrid – every appliance, fixture, or motor that requires power to run – will need to take that power within a certain voltage. Voltage must be regulated to meet different needs at different parts of the system. Voltage must also be "stiff" enough to absorb all of the loads that may draw power off of the system without substantially dipping or producing irregularities. There are several methods for controlling voltage to maintain a stable power source suitable to serve the loads on the system.

"Voltage support and regulation is important in a microgrid…. In standalone operation, the controller(s) for a microgrid must regulate voltage. In grid-connected mode, the local generators should not try to regulate voltage. For single generators, voltage control is relatively straightforward. For multiple generators, control of voltage becomes more complicated…. In addition to steady-state voltage control, other voltage characteristics are important. The microgrid must be stiff enough to provide torque to start motors within the microgrid. A utility source is normally stiffer than local generation within a microgrid. One option is to prevent large motors from starting or ensure that such motors have a soft enough start for the microgrid during standalone operation.

"The local generation should also provide a stiff enough source to limit voltage unbalance, harmonics, and voltage flicker." Alternative options including load shedding or fast inverter support. "To support local loads, the real and reactive power must be controlled to maintain adequate voltage and frequency. The control must match generation with load and accommodate changes in load, including step changes. Under the classic model, real power mismatches first affect frequency of the microgrid system, and reactive-power mismatches affect voltage. IEEE 1547.4-2011 describes several voltage and frequency control approaches." Voltage control methods include voltage droop and reactive power sharing; frequency control methods include speed droop, real power sharing and isochronous control. "In a microgrid, load shedding and/or load control is another option to help match generation and load for better voltage and frequency control."[152]

The rest of the section (pp. 53–55) includes good, concise discussions about metering and monitoring locations and key parameters for safe operation; strategies for supplying critical loads; and black start considerations including cold-load pickup and inrush current.

[151] NYSERDA 2014, p. 50.
[152] NYSERDA 2014, pp. 51–53.

Inertia

One of the biggest obstacles that microgrids face in the effort to generate a quality power signal is the inherent low inertia system. Inertia is the effect of kinetic energy in electrical generation; this physical momentum/inertia creates stability of voltage and frequency. [153] Massive turbines have significant inertia, and due to the electromechanical coupling of the system, this damps signal variation.[154] By having an inherent resistance to increase or decrease in speed (inertia) high inertia systems control the frequency of electricity generation much better than a system with low inertia. The macrogrid has high inertia; microgrids have lower inertia.
The power signal fluctuations in a low-inertia system can be very pronounced, and must be controlled quickly. Minimizing these fluctuations can be achieved in a few different ways; this can be done by either minimizing the effects of the fluctuations, or by artificially increase the microgrid inertia. Minimizing the effects can be achieved through use of high power energy storage technologies, or through load management and shedding techniques. Artificially increasing inertia can be carried out by de-loading wind and solar PV generators.

EPS Circuit Types and Implications for Microgrid Interconnection

[NYSERDA 2014] Section 5.4 Suburban and Rural Microgrid Arrangements and 5.5 Urban Microgrid Arrangements (pp. 55–78) provides an excellent detailed, clear and concise discussion about locating different microgrid design types in varied EPS system types. The distribution EPS has several configurations that influence microgrid design and interconnection issues, including:

- *Radial*. "In most cases, suburban and rural distribution systems are operated in a radial fashion from the substation source" with one feeder serving the customer or microgrid. [See NYSERDA 2014 pp. 55–56]
- *Loop*. "Looped systems, often used on suburban circuits, can have high reliability because of redundant sources. In a major event, looped systems can still have significant outages because of how widespread the damage is or because of the loss or the sub transmission supply…. Automating loop systems allows faster sectionalizing and restoration of service." [See NYSERDA 2014 p. 60]
- *Urban spot networks*. "Spot networks are often used to serve a single customer or multiple customers in close proximity to each other (commonly in a single building) that have large, concentrated electrical loads. Spot networks have at least two primary feeders and two transformers connected to a common low-voltage bus…. A spot network microgrid arrangement is more complicated than a basic radial system as there are multiple connection points to the utility system that are interfaced through network units…. Because most spot networks are relatively compact, the microgrid should have high reliability. Electrical lines feeding the customers in the network will normally be

[153] For example, see Introduction of *Impact of Low Rotational Inertia on Power System Stability and Operation*, accessed at: https://arxiv.org/pdf/1312.6435.pdf
[154] For an intuitive explanation, see: http://insideenergy.org/2015/06/15/ie-questions-what-is-inertia-and-whats-its-role-in-reliability/

relatively short and likely underground rather than overhead…. Having multiple interconnection points complicates many interconnection issues…. There can be a variety of serious overvoltage, power quality, and reliability issues created if the microgrid does not properly coordinate with the upstream protection timing and tripping levels at both the network unit level and the primary feeder level." [See NYSERDA 2014 pp. 69–70]

- *Urban grid networks*. "A grid network microgrid arrangement is more complicated than a typical spot network configuration.… Grid networks often have many geographically distant connection points to the utility system, all interfaced through network units, and cover a much larger physical area…. Electrical lines feeding the customers in the network will normally be relatively short, and in most cases, these will be underground rather than overhead. The network system adds complications beyond that of a non-network microgrid. Having multiple interconnection points complicates many interconnection issues…. There can be a variety of serious overvoltage, power quality and reliability issues created if the microgrid does not properly coordinate with the upstream protection timing and tripping levels at both the network unit level and the primary feeder level." [See NYSERDA 2014 pp. 74–76]

Each case discusses factors including benefits, safety, reliability, IEEE 1547 compliance, overcurrent protection, synchronization, voltage control and power control, metering and monitoring, supplying critical infrastructure, and black starting. Case examples include:

- Campus type microgrids with DERs in either single or multiple locations
- Microgrid connected to a suburban looped system
- Utility infrastructure adapted into a multi-facility microgrid at a commercial plaza
- Multi-facility microgrid with new distribution infrastructure parallel to the utility grid
- Urban microgrids on spot and grid networks

CONTROLS

Control systems are a defining feature of microgrids, and are vital to safe and cost-effective operation. They are the primary means of attaining the safety and performance requirements described above. Controls range in scale and complexity from the simplest inverter-based systems for single-DER, single-facility installations to intricate networks managing multiple different DG types across multiple microgrid facilities. Microgrid owners and developers must define what technical and economic performance they want their microgrid to achieve by controlling its DERs and managing its loads. They also must decide what type of disconnection and reconnection sequence they desire with regard to the EPS, and in accordance with utility interconnection requirements. These (and other) performance parameters determine what type of control system the microgrid should have.

The performance of a microgrid is contingent upon controls strategy. There are multiple ways to control a microgrid, with similar goals. Microgrid control strategy incorporates many potential functions, from high level control to the minutia of individual systems. Some important high level functions of the microgrid controls are:

- Match power output to power demand.
- Provide a stabilized power profile.
- Provide bi-directional energy flow.
- Allow for black-start operation in case of unforeseen issues.
- Enable participation in Demand Response programs (when available).
- Connect and disconnect from the grid when needed while maintaining power service delivery to the microgrid, either with a seamless "no blink or bump" rapid transition requiring costly automated equipment; or a slower, simpler, safer and cheaper open transition that could briefly drop all but the most critical loads and then reconnect them to onsite generation (manually or automatically) once in island mode.

Along with these high level tasks, there are other important tasks[155] that must be optimized to ensure proper functioning and longevity of the microgrid components. There are too many potential tasks to list here; examples include prioritizing renewable energy sources, managing energy supply to and from batteries to ensure batteries are not overcharged or deeply discharged, and regulating voltage at busses.

Controls and microgrid Sequence of Operation (SOO) address two main objectives: safe, effective transition to and from island mode (*i.e.*, disconnection from, and reconnection to, the EPS); and safe generation and distribution of electricity (and thermal energy) within the microgrid. Electricity networks at any scale must maintain power quality and stability within relatively tight tolerances, with greater or lesser range of allowable power quality depending on the nature of the load and their sensitivity to transients and faults.

Microgrids face unique challenges to ensure delivery of safe, consistent, quality power supply. These are similar to grid management tasks and challenges faced by the ISO or RTO at the regional scale or the EDC at the state level, but at a much smaller scale. Relatively speaking, microgrids have the disadvantage of fewer resources and less redundancy and inertia than the grid, yet also the advantages of a smaller span of control and fewer DERs to manage.

A 2014 publication by the IEEE-PES Task Force on Microgrid Control, *Trends in Microgrid Control*, provides a good overview of the issues. This source describes challenges in microgrid protection and control, including bidirectional power flows, stability issues, modeling, low inertia and uncertainty. "The microgrid's control system must be able to ensure the reliable and economical operation of the microgrid, while overcoming the aforementioned challenges. In particular, desirable features of the control system include" output control, power balance,

[155] For example, see *Energy Management and Control Algorithms for Integration of Energy Storage Within Microgrid***,** accessed at: https://sgdril.eecs.wsu.edu/files/files/Energy%20Management%20and%20Control%20Algorithms%20for%20ntegration%20of%20Energy%20Storage%20Within%20Microgrid.pdf

Demand Side Management (*i.e.*, load management), economic dispatch, and transition between modes of operation.[156]

Centralized (Master-Slave) vs. Decentralized (Peer-to-Peer) control strategies

Microgrid control strategies fall into two main categories: Master-Slave and Peer-To-Peer, with trade-offs that foster a hierarchical control strategy in each type.[157]

Centralized or Master-Slave controllers function in a top-down fashion with local DER or device controllers (slave) subservient to the central master controller. In this strategy, the master controllers utilize information from an array of sensors throughout the microgrid, develop a control scheme consistent with its programming, and control the slave units' operation accordingly. "A fully centralized control relies on the data gathered in a dedicated central controller that performs the required calculations and determines the control actions for all the units at a single point, requiring extensive communication between the central controller and controlled units."[158]

Decentralized / Peer-to-Peer controllers do not have a single master controller, rather the microgrid is controlled through communications between DER devices in the energy network. "[I]n a fully decentralized control each unit is controlled by its local controller, which only receives local information and is neither fully aware of system-wide variables nor other controllers' actions."[159] This a robust approach that allows the microgrid to function with loss of individual components. Utilizing a decentralized control strategy also allows the microgrid to incorporate plug-and-play concepts. This strategy is championed by Consortium for Electric Reliability Technology Solutions (CERTS)[160] in their microgrid concept.

"Interconnected power systems usually cover extended geographic areas, making the implementation of a fully centralized approach infeasible due to the extensive communication and computation needs. At the same time, a fully decentralized approach is also not possible due to the strong coupling between the operations of various units in the system, requiring a minimum level of coordination that cannot be achieved by using only local variables. A compromise between fully centralized and fully decentralized control schemes can be achieved by means of a hierarchical control scheme consisting of three control levels: primary, secondary, and tertiary. These control levels differ in their (i) speed of response and the time frame in which they operate, and (ii) infrastructure requirements (e.g., communication requirements). Although microgrids are not necessarily as geographically expansive as conventional power

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[156] IEEE-PES Task Force on Microgrid Control [IEEE-PES TFMC], *Trends in Microgrid Control*, 2014, pp. 1907–1908, accessed at: http://repositorio.uchile.cl/bitstream/handle/2250/126993/Trends-in-Microgrid-Control.pdf?sequence=1

[157] For a good overview, see IEEE-PES TFMC 2014.

[158] IEEE-PES TFMC 2014, p. 1909.

[159] IEEE-PES TFMC 2014, p. 1909.

[160] https://certs.lbl.gov/initiatives/certs-microgrid-concept

systems, they can benefit from this control hierarchy… because of the large number of controllable resources and stringent performance requirements."[161]

"Primary control, also known as local control or internal control, is the first level in the control hierarchy, featuring the fastest response. This control is based exclusively on local measurements and requires no communication. Given their speed requirements and reliance on local measurements, islanding detection, output control and power sharing (and balance) control are included in this category. In synchronous generators, output control and power sharing is performed by the voltage regulator, governor, and the inertia of the machine itself."[162] This method has the highest sample rate, and must monitor DERs with high frequency due to the rate at which deviations can affect the microgrid.

"*Secondary control*, also referred to as the microgrid Energy Management System (EMS), is responsible for the reliable, secure and economical operation of microgrids in either grid-connected or stand-alone mode…. For the EMS architecture, two main approaches can be identified: centralized and decentralized architectures. Secondary control is the highest hierarchical level in microgrids operating in stand-alone mode, and operates on a slower time frame as compared to the primary control".[163] This control level becomes more difficult as more variable energy sources are utilized; with increased variability in the sources, the controls must be able to have a high dispatch rate. Another important task is correcting fluctuations in the output of the primary controls, such as voltage and frequency deviations.

Tertiary control is the highest level of control for grid-connected microgrids or for systems that consist of multiple microgrids. This control level ensures that the microgrid interfaces with other microgrids or the host grid. Tertiary control is the highest level of control and sets long term and typically "optimal" set points depending on the requirements of the host power system. This tertiary control is responsible for coordinating the operation of multiple microgrids interacting with one another in the system, and communicating needs or requirements from the host grid (voltage support, frequency regulation, etc.)…. Tertiary control can be considered part of the host grid, and not the microgrid itself."[164]

"[Tertiary control] typically operates in the order of several of minutes, providing signals to secondary level controls at microgrids and other subsystems that form the full grid. Secondary controls, on the other hand, coordinate internal primary controls within the microgrids and subsystems in the span of a few minutes. Finally, primary controls are designed to operate independently and react in predefined ways instantaneously to local events."[165]

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[161] IEEE-PES TFMC 2014, p. 1909.
[162] IEEE-PES TFMC 2014, p. 1910.
[163] IEEE-PES TFMC 2014, p. 1910.
[164] IEEE-PES TFMC 2014, p. 1910.
[165] IEEE-PES TFMC 2014, p. 1910.

Microgrid energy management

The NJBPU 2016 report Section 4 "Advanced Microgrid Energy Manager" (see pp. 43–47) provides a good discussion of microgrid energy management, as enabled by controls and in relationship to the grid. It describes two types of microgrid energy management functions, which are not clearly segregated in practice. "The DER Energy Manager operates the functions of the microgrid to optimize the DER operations within the microgrid. The Systems Energy Manager manages the two way power flow and interconnection to the grid to optimize utilization."[166] For the regional grid, the effective System Energy Manger is ISO-NE. For a Level 1 or Level 2 microgrid, both functions are typically performed by the same entity (*e.g.*, the owner). For a Level 3 microgrid, in theory it could be either the EDC and/or the owner. "The key function for the Systems Energy Manager is to maximize the advance microgrid benefits and minimize the costs to both the advance microgrid customers and the customers of the distribution grid."[167]

Controls complexity, interoperability, and cost considerations

Controls are key to microgrid performance that meet these standards, but there is little standardization in controls equipment, and many proprietary systems and vendors proliferate in the marketplace. This reflects ongoing innovation but also a source of risk for microgrid developers and operators, particularly when attempting to integrate multiple DERs and IT systems from different manufacturers. Microgrids themselves defy standardization; every situation is different and every microgrid is a snowflake. This compounds the challenges of controls systems complexity and cost.

"There's broad agreement that most of the technical barriers of microgrids are solved, but Michael Burr of the Microgrid Institute says, 'the biggest remaining technical barrier is the lack of affordable, advanced microgrid control systems capable of managing all kinds of microgrids—from single-building nanogrids to large multi-node community microgrids. There are many players in the market but few are offering mature and flexible microgrid control solutions.'"[168]

Industry efforts are underway to promote greater DER interoperability and reduce complexity and cost. Duke Energy has organized a multi-stakeholder effort called the Coalition of the Willing (COW) to develop interoperability standards that can enable diverse grid-edge technologies to integrate with each other in the field.[169] Participating vendors must conform to open, interoperable messaging protocols, and must implement publish-subscribe protocols such as Data Distribution Service (DDS) or Message Queue Telemetry Transport (MQTT).[170] COW developed a "field device interoperability framework, known as the Open Field Message Bus (OpenFMB™). This framework is a standards-based solution to reduce implementation

[166] NJBPU 2016, p. 43.
[167] *Ibid*, p. 45.
[168] ILSR, *Mighty Microgrids*, 2016, p. 27.
[169] https://www.duke-energy.com/our-company/about-us/smart-grid/coalition
[170] https://www.greentechmedia.com/articles/read/Microgrids-Drive-Dukes-Coalition-for-Grid-Edge-Interoperability

complexity and integration costs and was formally adopted by two task forces within the Smart Grid Interoperability Panel (SGIP) and the North America Energy Standards Board (NAESB)."[171]

Policy recommendation: OER could consider requiring or providing preferential scoring for microgrid projects to use the Duke COW interoperability standards.[172]

Policy recommendation: OER could consider requiring or providing preferential scoring for microgrid project testing of their control schemes with a real-time hardware-in-the-loop (HIL) test platform[173], such as that developed by MIT-Lincoln Lab's Erik Limpaecher and team. MIT-LL has offered to test microgrid controllers with their HIL testbed system that enters microgrid DER data and simulates DER performance to test the connected controller. MIT-LL could perform this service for a modest fee, and ideally access to microgrid performance data. Oak Ridge National Laboratory has also offered a similar service. Tested validation of microgrid design could reduce risk and increase stakeholder confidence in a microgrid development, particularly for larger and more complex microgrids with multiple DERs.

4. Performance characteristics

This section highlights methods and metrics for evaluating microgrid performance.

TECHNICAL

Microgrid technical performance characteristics include:

- Critical loads: type, size (kW, therms), demand profile (kW), energy use (kWh, MBH) power quality tolerances.
- DER generation capacity: Fuel-to-energy conversion efficiency, output in kW, kWh, MBH, ramp rates, response time, fuels, EUL (operating hours).
- DER storage capacity: kW / kWh, depth of discharge, EUL (cycles).
- DER dispatch strategies: Transition time to serve loads upon loss of electric service, load shedding, load following ramp rates.
- DER fuel: type, supply strategies, duration of operation in island mode.
- Controls and PCC transition: Time to synchronize, time to disconnect.
- Controls capability in synchronous or asynchronous relationship the grid: Response time, Sequence of Operation (SOO) steps.
- Mitigation & adaptation to Design Basis Threat(s): ability to withstand inundation, wind speeds, seismic forces; physical and cybersecurity protection and standards compliance.

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171 https://www.duke-energy.com/our-company/about-us/smart-grid/coalition
172 https://www.duke-energy.com/our-company/about-us/smart-grid/coalition
173 http://info.typhoon-hil.com/microgrid-controller-testbed-demo-using-hardware-in-the-loop

ECONOMIC

Microgrid technical performance characteristics include:

- Procurement model type and funding source(s), cost of capital.
- Capital assets: Installed cost, O&M cost, 20 year NPV.
- Energy costs/savings: Fuel cost, retrofit *vs*. baseline utility costs, net metering credits, incentives and funding support,
- Revenue sources: DR, ISO ancillary services, wholesale/retail energy market transactions.

Rhode Island's Least Cost Procurement and Docket 4600 Total Cost Resource Test processes have developed new Cost-Benefit Analysis (CBA) metrics to capture non-traditional sources of value from DERs to parties including the power sector, customer level, and societal benefits aspects.

5. <u>Value chain: Microgrid benefits and value streams</u>

Microgrid benefits (and costs) accrue to different parties: some to the owner, some to the utility, some to society. See Figures B-7 and B-8.

Figure B-7: Microgrid Benefits Accrual[174]

Benefits	Users	Utility	Society
Energy benefits	☑	☑	
Reliability benefits	☑	☑	☑
Power quality benefits	☑	☑	
Environmental benefits			☑
Safety, health and security benefits	☑		☑

[174] NYSERDA 2014, p. 100.

Figure B-8: Microgrid Costs Accrual[175]

Costs	Owner	Utility	Society
Project planning and administration costs			
Project design	☑		
Building and development permits	☑		
Efforts to secure financing	☑		
Marketing the project	☑		
Negotiating and administering contracts	☑	☑	
Capital investment costs			
Energy generation equipment	☑		
Energy storage equipment	☑		
Energy distribution infrastructure	☑		
Upgrades to macrogrid		☑	
Operation and maintenance costs			
O&M for generation and storage equipment	☑		
O&M for distribution infrastructure	☑		
O&M for dedicated utility infrastructure		☑	
Environmental costs			
Capital costs of emissions control equipment	☑		
O&M of emissions control equipment	☑		
Emission allowances	☑		
Human health and ecological damage			☑

Not all benefits can be monetized. Different microgrid procurement "business models" provide varied opportunities to monetize potential mixes of value streams. Where and how microgrids provide value depends upon the specific assets and aspects of a microgrid. Distributed generation (DG) is a "prime mover" of value; controls enable islanding, optimal economic dispatch of generation, demand response (DR) and ancillary services revenue; energy storage (ES) provides greater frequency regulation capabilities. These components contribute to the microgrid value chain. Value chain factors can include operating revenues and cost reductions, avoided asset damage and business interruption costs, COO and mission continuity benefits, risk reduction, and insurance premium savings. Value streams that are available to the microgrid/DER owner could be included in cost/benefit analysis (CBA).

[175] NYSERDA 2014, p. 102.

Figure B-9: Microgrid Value Stream Taxonomy[176]

Figure 5.1 – Microgrid Value Stream Taxonomy

Economic

- ***Direct***
  - Energy cost reductions
    - Reduced purchases of electric generation, transmission & distribution services
    - Reduced purchases of fuel for on-site thermal energy demand
    - Reduced purchases of ancillary services
  - Sales of excess electricity to the macro-grid
  - Participation in demand response programs
  - Provision of ancillary services to the macro-grid
- ***Indirect***
  - Reduced electric T&D losses
  - Deferred electric T&D capacity investments
  - Utility option value for long-term planning purposes
  - Enhanced electricity price elasticity
  - Support for deployment of renewable generation

Reliability & Power Quality

- Reduced power interruptions
- Enhanced power quality

Environmental

- Reduced emissions of greenhouse gases
- Reduced emissions of criteria pollutants

Security and Safety

- Safe havens during power outages

For a detailed discussion, see NYSERDA 2010 Part 5.0 Integrated Analysis of Microgrid Value Streams.

[176] NYSERDA 2010, p. 70.

Figure B-10: DER Benefits *vs*. Microgrid Benefits[177]

Table 4-1: Distributed Energy Resource Benefits versus Microgrid Benefits

Benefit Description	DER Alone	†MG	*MG+
Economic			
Direct			
Facility Energy cost reductions	✓	✓	✓
Participation in Ancillary Services markets	✓	✓	✓
Sales of excess electricity to the macro-grid	✓	✓	✓
Participation in demand response programs	✓	✓	✓
Optimization of Assets based on pricing signals and real time energy markets			✓
Indirect			
Reduced electric T&D losses	✓	✓	✓
Deferred electric T&D capacity investments	✓	✓	✓
Support for deployment of renewable generation	✓	✓	✓
Reliability & Power Quality			
Ability to operate absent macrogrid	✓‡	✓	✓
Reduced facility power interruptions		✓‡	✓
Enhanced facility power quality		✓‡	✓
Increase power facility electricity reliability		✓‡	✓
Ability to operate absent electricity and gas infrastructure		✓‡	✓
Environmental			
Reduced emissions of greenhouse gases	✓‡	✓‡	✓‡
Reduced emissions of criteria pollutants	✓‡	✓‡	✓‡
Security & Safety			
Safe havens during power outages			✓
Ability to support community during long term outages			✓

Table adapted from NYSERDA Report: *Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State, Final Report*. (2010)

†Considering only the islanding capabilities of microgrids

*Considering islanding capabilities and the benefits of coordinated (microgrid) controls

‡The response here is truly "it depends". E.g., if clean/green electricity is stored in a battery, then the loss of energy to convert and reconvert back into electricity means that more energy has to be consumed. Conversely, if battery storage helps stabilize intermittent renewables feeding the distribution grid, then the grid requires fewer non-renewable fuel-fired central plants to generate power / VAR etc. for grid stabilization.

DIRECTLY MONETIZED BENEFITS

Directly monetized benefits are highly dependent upon circumstances. Microgrid components that contribute to each value stream are listed in [brackets]. Benefits include:

- Reduction in purchased electricity costs [DG, ES, controls]
- Reduced purchases of grid electricity (because of energy generation and storage capabilities)

177 MA 2014, p. 4-2.

- Reduced purchases of fuel for on-site thermal generation
- Net cost of DER output is cheaper than existing fuel costs / annual “energy spend” [*e.g.*, CHP might increase natural gas costs but lower electricity costs more]
- Insulation from price volatility of electricity, fuel. SIMILAR: enhances price elasticity of electricity demand.
- Peak shaving: offset highest cost kWh power, reduce kW demand charges
- MG might sell energy in-/directly to customers, bypassing EPS fees & losses.
- Revenue from dispatch of generation [DG, controls]
- Blue sky operations: sell excess / full output when worthwhile
- Participation in Forward Capacity Markets as generation, demand, or efficiency [DG, ES, controls]
- Revenue from dispatch of electricity storage [ES, controls]
- Peak shaving: offset highest cost kWh power, reduce kW demand charges
- Load shifting: time-based rate fluctuations can be arbitrage opportunities.
- Sell stored power to grid (see ancillary services)
- Revenue from sale of ancillary services: Voltage/frequency regulation, balancing services, peak load support, black start capability [DG, ES, controls]
- Frequency or active power support often compensated based on availability rather than usage
- Could also incur additional costs- fuel and opportunity cost, associated with DG operating below full capacity to provide reserve. Actual benefit is marginal revenue – marginal O&M cost. O&M cost would be lower here than for voltage support
- Voltage or reactive power support [DG, ES, controls]
    - Same problem of opportunity cost
    - Less compensated than frequency support
    - Creates additional costs of less active power output and additional equipment required
- Black start support provides power to kick start large generators [DG, ES, controls]
    - The above services probably will be unavailable in island mode (save black start)
- Revenue from demand response [DG, ES, controls]
- Renewable power exported to the grid potentially eligible for feed-in-tariffs [DG, ES, controls]
- Incentives and tax credits
    - Load reduction incentives & rebates
    - RE DG tax benefits: FITC, MACRS
- Capacity Cost Savings
    - Deferred generation capacity
    - Deferred transmission and distribution capacity
- Reduction of energy losses
    - Benefits of supplying DC loads with DC resources
    - Reduced losses in distribution network (line losses, voltage transformation losses)
    - Reduction of losses associated with non-optimized CHP balance
- Power Quality Benefits
    - Avoided losses associated with electrical fluctuations: economic, equipment

damage

- Avoided loss due to reliability improvements
    - Reduced risk of business interruption and loss of production
    - Avoided production loss, shutdown days, potential insurance premium reductions

Other potential energy market value streams include:

- Energy price arbitrage
- Negawatt market
- Operational reserve market
- Auxiliary market service
- Power factor services
- Price impact of reduced energy demand (system wide benefit)

INDIRECTLY MONETIZED BENEFITS

Indirectly monetized benefits include:

- Reduction in loss from improvements in power quality (less fluctuation in voltage and frequency)
- Avoided loss due to reliability improvements
    - Risk of business interruption, loss of production via onsite generation and MG controls that enable islanding for continuity of operations
- Reduction in major outages frequency and duration

<u>Microgrid reliability considerations</u>

Microgrids are often less reliable than the EPS, based on a small set of onsite DERs which have higher average downtime than the generation portfolio of the grid. Yet grid-connected microgrids often are more reliable than is the EPS alone. A grid-connected microgrid is more likely to be able to serve its loads during grid outages, while the grid is highly likely to be available to serve microgrid loads during DER downtime.

SAFETY AND SECURITY BENEFITS

Public safety benefits include:

- Maintain community critical facility operations during outages
- Support for emergency services during outages
- Provision of community refuge during an emergency or extended outage
- Reduction in reliance upon fuel supply using renewables and storage provides some insulation from interruptions in fuel supply
- Making the grid more decentralized reduces the risk of successful attack
- Encourages energy supply independence
- Islanding capability offers security benefit reduces the risk of grid disruptions

- Provides emergency power services to LMI community members, who often lack the resources to evacuate or safely shelter in place

PUBLIC AND ENVIRONMENTAL HEALTH BENEFITS

Microgrids can contribute public and environmental health benefits, including:

- Enable greater use of renewable generation
- Systems possess greater load-following capabilities
- Loads and generating assets are collocated
- Allows for use of assets too small for macrogrid inclusion
- Demand response / energy generated offsets power produced by peaker plants (which are environmentally more damaging)
- Reduced CO_2 emissions / reduced CO_2 intensity of generation assets
- Reduced pollutant emissions
- Provides outlet for growth of renewable energy technology
- Reduction in pollutant emissions

ADDITIONAL COMMUNITY BENEFITS

Additional community benefits can include:

- Corporate Social Responsibility and education benefits
- Engagement of consumers and employees
- Visibility of energy use
- Grows microgrid industry, develops local economy, creates local expertise
- Encourages community/city scale independence
- Involves diversity of public and private users; fosters community connectedness

REGULATORY VARIABLES

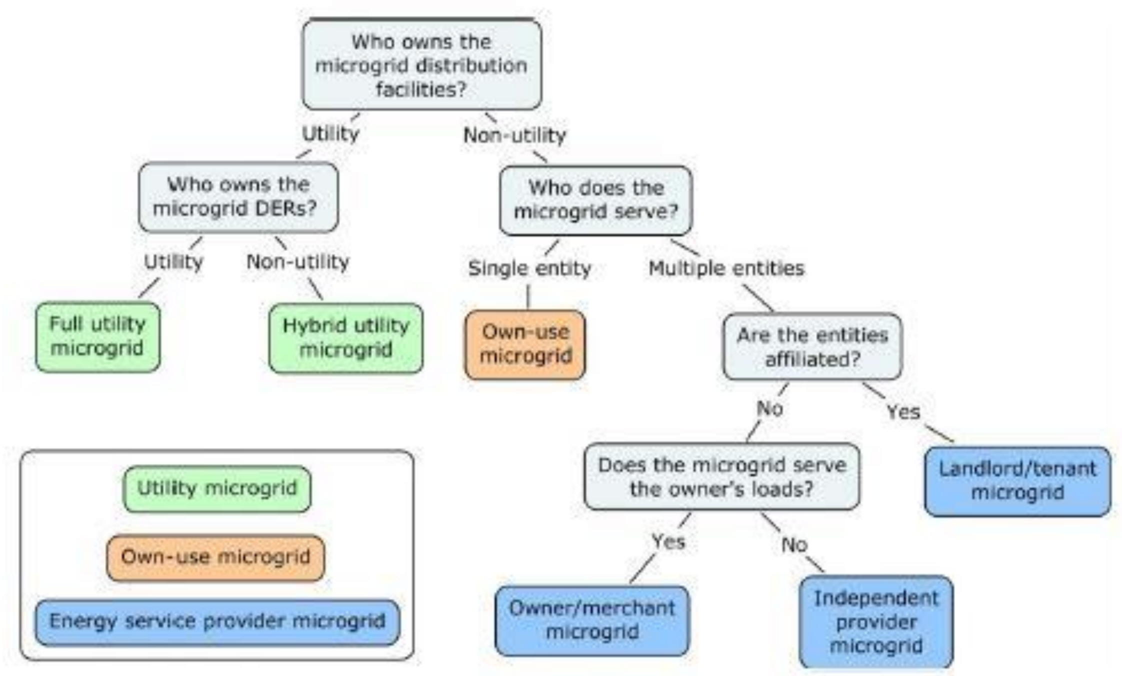
Regulatory policy changes to rules and rates can influence microgrid benefits for better or worse over the life of a project. This regulatory risk is a source of uncertainty in microgrid valuation and financing. Variables include potential changes to:

- Net metering rules
- Demand response programs
- Ancillary services contract terms
- Standby charges
- Utility rate structure- time variance
- Feed-in tariffs

6. Ownership, procurement and financing strategies and business models

There are several options for who owns and controls a microgrid: the customer or facility owner, a third party, the utility, or a mix. (See section B2 and B3 for further discussion.) Figure B-11 from the NYSERDA 2014 report depicts some ownership types not discussed here, yet suggests a useful typology.

Figure B-11: Microgrid Ownership Typology[178]



Whomever owns the microgrid, the utility will have some influence on microgrid operations and islanding via the interconnection agreement at least. Collaboration and communications between the microgrid and EDC is essential, as the EDC needs to know when a (larger) microgrid's block of load is going to leave or rejoin the EPS.

There are potentially many colors of money for microgrid financing, including:

- Grant funding: State, Federal HUD, DOE, USDA, etc.
- Customer: Direct purchase, capital investment of owner funds, C-PACE
- Public: Revenue bonds, G.O. bonds, grants, ESPC, PPA, ESA, TELF
- Private: Cash, loans, bonds

[178] NYSERDA 2014, p. 109.

Potential procurement and financing options are described below, categorized by ownership type.

Customer: Direct purchase

An eligible customer with sufficient funds or borrowing capacity could directly purchase a microgrid installation. In case-specific conducive circumstances, some DERs and energy efficiency measures could result in operating cost savings that provide positive cash flow sufficient to pay back microgrid infrastructure investments within a reasonable period. In other words, some microgrids can pay for themselves in an acceptable time frame.

Customer (private or nonprofit sector): Commercial Property Assessed Clean Energy (C-PACE)

RI Infrastructure Bank (RIIB) provides Commercial Property Assessed Clean Energy (C-PACE) financing. This mechanism allows financing of energy efficiency upgrades or renewable energy installations for eligible buildings. An eligible public, institutional or MFH property owner can arrange financing for energy improvements, which is attached to the property via an assessment that is senior to mortgage (akin to a sewer lien). The loans are repaid over the assigned term (typically 15 or 20 years) via an annual assessment on their property tax bill. Host municipal governments process financing payments, then forward the funds on to the lender. RIIB's program specifically lists "microgrids" as an eligible measure.

Customer (public, institutional or nonprofit sector): Retrofits & new construction: Energy Savings Performance Contracts (ESPCs)

An Energy Savings Performance Contract (ESPC) employs third-party implementation and financing to implement energy and water efficiency upgrades, at no up-front cost to the facility Owner. The financing is repaid from the resulting guaranteed energy savings over the contract term (typically around 15 years). Below is an outline of the typical process.

The Owner can hire an Owner's Representative (OR) to support the ESPC process, ideally from the initial planning phase. The Owner issues an RFP to select an Energy Services Company (ESCO). ESCOs submit proposals with proposed Energy Conservation Measures (ECMs) and estimated savings based on preliminary assessments of a sample subset of buildings.

The Owner chooses one ESCO and negotiates an agreement with that ESCO to conduct an Investment-Grade Audit (IGA) over 3–6 months of the buildings in the project. The Owner doesn't pay for the IGA separately if an ESPC is implemented, but the Owner encumbers the risk of the ESCO's "walk away" contingency fee in case the Owner decides not to proceed with the ESPC after the IGA is complete. Based on the IGA the ESCO proposes a portfolio of ECMs on a portfolio of buildings, and guarantees the resulting savings. This portfolio approach bundles shorter-payback measures (*e.g.*, lighting upgrades) with longer-payback measures (*e.g.*, boiler or chiller upgrades, window replacements) to yield a composite payback for the project that can be financed within the contract term, with guaranteed savings sized to cover the financing repayments. The IGA process enables the Owner to identify the ECMs it prefers. The IGA provides hard information with open-book pricing to inform the Owner's decision about what to implement. The self-funding ESPC's cost savings guarantee minimizes risk, regardless of project size.

Based on the IGA, the Owner negotiates an Energy Services Agreement (ESA or ESPC) with the ESCO to implement the desired ECMs with savings guaranteed by the ESCO. Based on the savings guarantee, the Owner arranges financing to pay the ESCO to do the work. Positive cash flow generated by the utility cost reductions resulting from energy savings are used by the Owner to repay the financing over the contract term (*e.g.*, 15 years). In effect the Owner's buildings get capital improvements without capital expenditures today, paid for by tomorrow's energy savings. The financing is repaid with money the Owner has to spend anyway if no ESPC occurs. Typically Owner capital funds are not used. In public sector agencies a Tax-Exempt Lease Purchase (TELP) or Tax-Exempt Lease Financing (TELF) is often used. Very few ESPC projects fail after the IGA, fewer with OR support.

Typical minimum requirements are 100,000 square feet (SF) of facility area, although at least 250,000 SF is preferred. ESPCs can fund a certain amount of capital investment that does not directly provide savings, which can include microgrid infrastructure. The major ESCOs have the capability and are well positioned to develop microgrids in this manner, and several have relevant experience. ESPCs can provide an integrative framework to accomplish energy and water load reduction, DER installation (*e.g.*, CHP), and other microgrid infrastructure.

ESPCs also can be used with new construction and for fleet conversions. For new construction, an energy model simulation can be constructed for the facility as if it were to be built to minimum code compliance. The model provides a projected energy use baseline that the ESCO references to develop the technical and financial proposal for ECMs such as more efficient equipment. One of the first applications of this approach was at the Foster-Glocester Regional School District and Ponaganset High School and Middle School in RI, including a fuel cell.[179]

<u>Customer: Community ownership</u>

This ownership model might require enabling legislation, or administrative or regulatory precedent approval. RI's new community remote net metering program could potentially enable large-capacity, shared-ownership "solar plus storage" installations to provide power to adjacent critical facilities during outages—although probably not to any of the owners' facilities, except by happenstance.

<u>Customer/third party: Energy Improvement Districts and similar structures</u>

This ownership model would require enabling legislation. An Energy Improvement District (EID), Energy Innovation District, Energy Reliability District or similar structure is typically a

[179] http://www.conedsolutions.com/Libraries/Case_Studies/Foster-Glocester_Regional_School_Dsitrict.sflb.ashx

nonprofit or tax-exempt entity chartered by a municipality that is empowered to make investments in DERs and microgrids. In CT, EIDs can develop and operate DERs including generation of up to 65 MW and energy efficiency investments; issue revenue bonds and charge fees for energy; and finance, own, lease, or contract for microgrid development and operation.

Third party ownership

Microgrid third party ownership and operation is a possibility where DERs are large enough (*e.g.*, <1 MW or $1 million), or the overall business case is sufficiently profitable. There are various approaches to third party ownership, including Power Purchase Agreements (PPAs) and Energy Services Agreements (ESAs) where contractors provide customers with a mix of design, construction, ownership and operation of DERs and/or microgrid infrastructure and agree to provide energy commodities or services for compensation. Some third party ownership models could challenge the EDC's monopoly franchise, and/or require PUC regulatory oversight.

Utility ownership

This ownership model would require PUC support in a restructured state with an EDC. The authors do not recommend this level of experimentation with the regulatory regime for the purpose of microgrids alone; see section D2.2 for further discussion. Utilities might be able to rate base microgrid investments, with regulator approval. However, the traditional obligation to serve all customers informs a common concern among utility decision makers about "socializing" local microgrid costs across the entire ratepayer base. This raises equity issues depending on the locality of the investment. Microgrid-specific custom tariffs are one strategy to address this concern.

In RI the grid would require a substantial amount of distribution automation, advanced metering infrastructure and similar "smart grid" type investments to enable adaptation of the EPS to create or accommodate Level 3 multi-user microgrids, and Level 2 campus microgrids where the EDC owns the distribution infrastructure. Microgrids could be considered a non-wires alternative to EPS hardening.

Hybrid ownership

In hybrid ownership models, a regulated electric utility or EDC owns and operates the EPS infrastructure and the microgrid distribution infrastructure, while customers or third parties own the DERs. Alternative examples could include utility ownership of generation and customer or third party ownership of energy storage. There are relatively few examples in the mainland U.S., and they are uncommon among EDCs in restructured or "deregulated" electricity markets in states including RI, in part due to restrictions on EDC ownership of generation capacity. In CT and NJ programs the utility owns part or all of the microgrid distribution infrastructure, which could be considered a form of hybrid ownership. Another approach could be to have the EDC enter into PPA/ESA agreements for islandable DER capacity located within Level 2 or Level 3 microgrids, and resell the energy to microgrid customers.

7. Market barriers

Microgrids face numerous barriers to development in the marketplace. Examples are described below.

Legal risk (real and perceived)

Real or perceived legal and regulatory risks include:

- Challenge to utility franchise
- Selling power as a non-utility entity, non-qualified generator
- Distributing power across ROW or utility easement

Administrative risk: Permitting constraints on generation technologies

Success is not certain and dependent on Authorities Having Jurisdiction (AHJ).

Administrative risk: Interconnection approval

Success is not certain and dependent on the EDC.

Organizational and technical risk

Marketplace & administrative (programmatic) risk: There are many microgrid types, applications and business models; situations vary and often don't readily scale or replicate (especially in retrofit projects with site-specific determining factors).

Marketplace risk (supplier and customer): Both facility owners and vendors/contractors have limited experience with complex microgrids, and generally lack the specialized knowledge required to finance, design, construct, commission and operate microgrids. This is changing as marketplace experience increases.

Customer: *Constrained resources*. Many CF owners lack resources for qualified staff to operate microgrids. Many retrofit microgrids are too small to support economical third party ownership / operations.

Customer: Public procurement challenges. Barriers related to public agencies include:

- Public agencies tend to have long budget cycles and limited discretionary funds for shorter-notice expenditures for planning and implementing capital projects
- Challenges of pricing and funding feasibility studies, equipment, consultants and vendors less than 1 fiscal year in advance
- Many stakeholders with veto power and cyclical turnover during long project development periods

Customer: Private facility ownership. Barriers related to private sector facility owners include:

- Short run focus, hesitancy to make long term investments in commercial property
- Remote layers of corporate ownership approval required, e.g., chain businesses
- Microeconomic constraints on expenditures for macroeconomic/public benefit

Supplier: Proprietary controls (and other equipment) risk. The lack of comprehensive standards and the potential mix of equipment and controls from different OEMs can increase technical risk in microgrid projects, due to interoperability issues. Low-bid component purchasing can exacerbate this challenge. Open protocols are preferred for "plug and play" solutions and operational risk reduction. Industry stakeholder efforts such as Duke Energy's Coalition of the Willing are attempting to address this barrier with voluntary standards.

<u>Technical risk</u>

Technical risk factors are discussed in section B4.3. These include:

- Limited generation options with fuel supply risks
- Sufficient natural gas supply required for CHP
- PV(+ES), wind are intermittent
- Power quality and voltage stability within MG
- Load following, load shedding
- Control of multiple generators
- Electrical distribution infrastructure and operations challenges and requirements
- Maintaining power quality, voltage stability, frequency regulation within MG
- Safe disconnection and reconnection to EPS
- Controls complexity and challenges (affects economic risk)

<u>Technical and economic risk: existing CFs not designed or configured to facilitate retrofit MG</u>

The characteristics of an existing critical facility (CF) can have a significant impact on the technical and financial feasibility of a retrofit project to form a Level 1 or Level 2 microgrid. Mechanical and electrical systems type and configuration, electrical and natural gas supply systems, and energy use patterns influence the compatibility of potential retrofit DERs and microgrid infrastructure.

For example, most facilities require natural gas supply to enable CHP as an option, although in cases compressed or liquid natural gas or propane might suffice (though large storage capacity could be required). If a building has a central mechanical room with hydronic or steam heat, it might be a good candidate for CHP prime movers that produce thermal energy in a compatible temperature range; but extensive modifications might be required if the building uses many dispersed HVAC rooftop units (RTUs) or Direct Expansion (DX) refrigerant-based systems. Basement-level mechanical or electrical systems might have to be elevated or otherwise flood-proofed if there is an inundation risk, which can be very costly. If a building has no existing critical loads circuit, it can be expensive to re-wire the facility to create one that can isolate mission-critical loads. Many buildings lack open ground or roof area that is suitable for PV installations due to factors such as limited square footage, shading, orientation, structural load-bearing capacity, and age.

Economic risk

High capital cost. Microgrids can involve significant capital investment, including:

- Generation options – potential cost savings or cost increases
- Electrical infrastructure (especially hardened) – probable cost increases
- PCC, controls, sensors, communications, protective relays, switchgear – potential or no cost savings, probable cost increases

High operating costs. Microgrids can involve significant variable costs, including O&M for CHP, controls, etc. Operating cost savings are possible due to DERs.

Uncertain and evolving revenue models. Lack of experience with microgrid operation and challenges to monetizing and aggregating value streams increases risk in areas including:

- DR, ancillary services
- Challenges to some owners for selling energy
- LG: ISO markets are changing rules around participation (trends are generally good for DERs/MGs), utilities are changing rates, etc.

Utility rate risk. Rates can change over project life, or microgrid formation can put customer in a different rate class. Uncertainty about utility standby charges can also be a factor in microgrid planning.

Turnkey projects require minimum scale, uncommon in many retrofits. Sub-MW projects such as Level 1 microgrids can find it difficult to attract third party investment or operations due to small project size.

Inconsistent valuation of benefits. The highly case-specific nature or microgrids and lack of unified standards for valuation of non-traditional benefits complicate microgrid planning. There remain many challenges for monetizing benefits and "stacking" multiple potential value streams, particularly where costs and benefits accrue to different parties.

8. Market status

Microgrids' market status can be considered both in terms of the market maturity of microgrid components *vs*. microgrid development. Both microgrid types and prospects (of each type) vary. Legal and regulatory barriers and high cost pose formidable barriers to rapid adoption. State policies and programs have a strong influence on the marketplace, and grant-funded programs have had varied success yet account for a large share of recent installments. Such programs can be said to be "ahead of the marketplace" until stakeholder awareness and experience increase, and business models and technologies mature. There is much buzz about microgrid growth, but the sheer scale of marginal investment are small. Slow growth, large potential, and significant impacts of policy levers will shape the marketplace.

"Microgrids are currently uncommon, with 1.3 gigawatts of capacity online in 2015, about 0.1% of total U.S. installed electric generating capacity. [Eighty] percent of operational microgrids exist in just seven states, mostly those that actively designed laws to accommodate their expansion. Some analysts predict their number to double or triple in the next five to ten years."[180]

Figure B-12: Microgrid Capacity in Leading States[181]

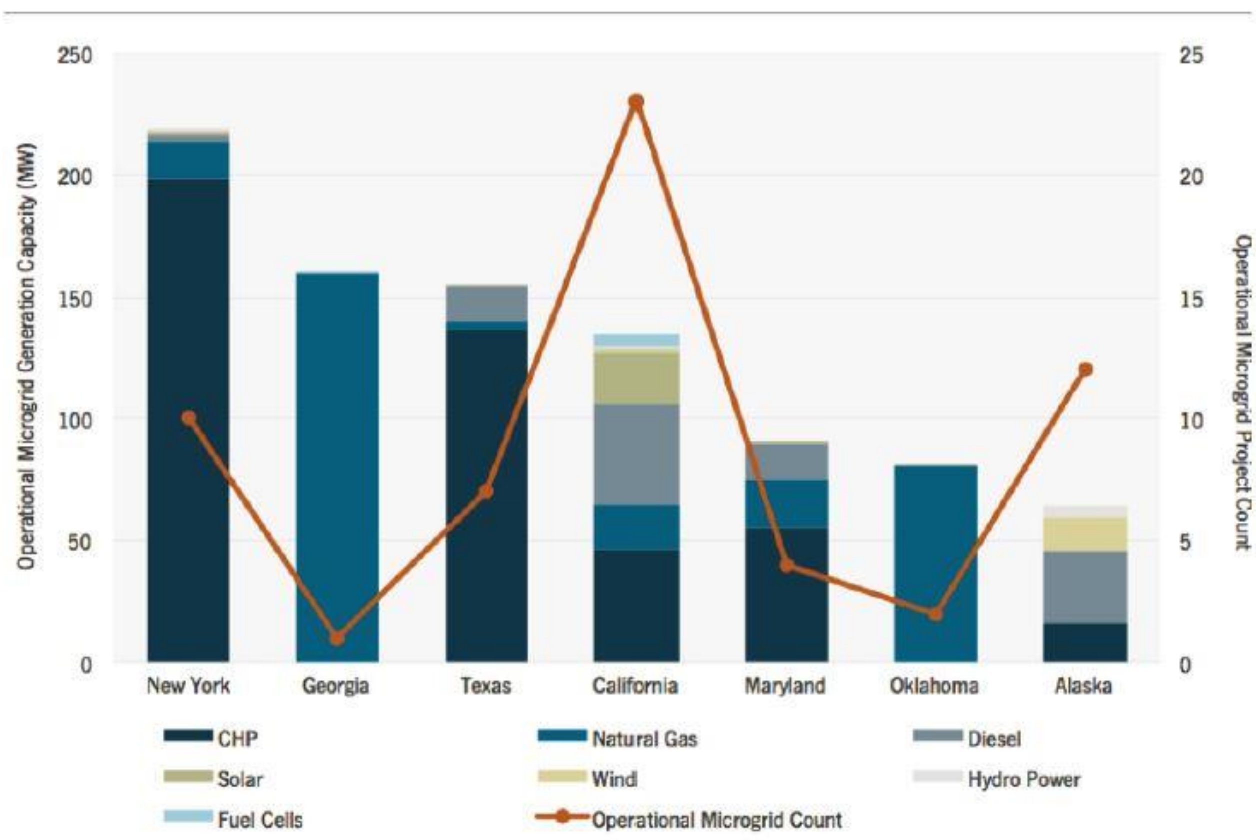
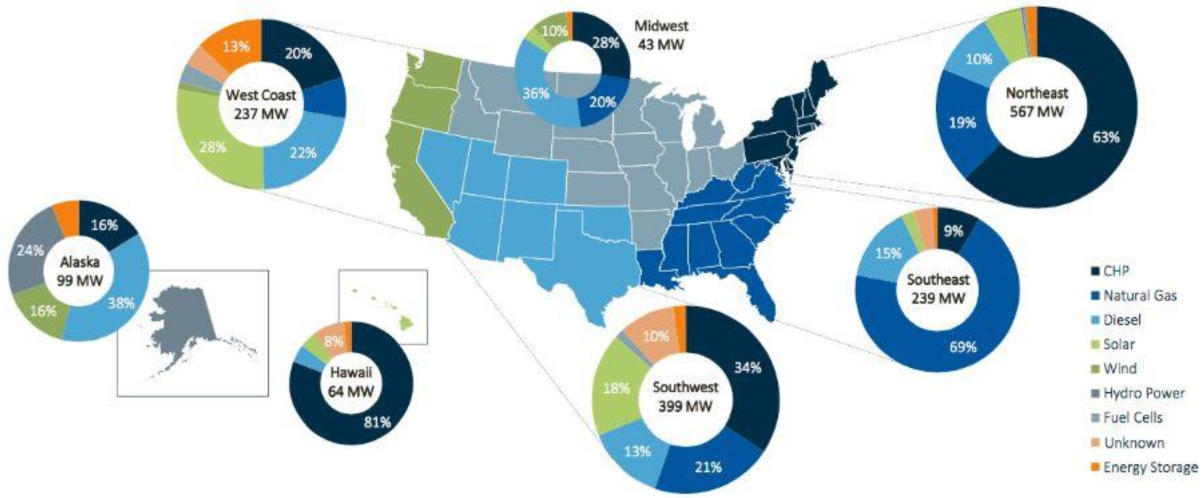


Chart credit: GreenTech Media Research

[180] ILSR, *Mighty Microgrids*, 2016, p. 7.
[181] ILSR, *Mighty Microgrids*, 2016, p. 8.

Figure B-13: Microgrid Capacity by Installed DG Type and Region



Graphic: GreenTechMedia.

"With climate change likely to worsen or make storms like Sandy more frequent, Northeastern states provided $400 million to fund the development of community microgrids and resilient infrastructure. Because of these programs, more than 40 municipalities in the Northeast will have microgrid projects completed in the next year."[182]

9. Available cost (capital and operational) data

Microgrids are highly case-specific, with a variety of types and business models and a strong role for grant funding. Cost data should be viewed with that caveat. Case examples include:

- Collections of brief case study examples of microgrids are provided by Lawrence Berkeley National Laboratory (worldwide)[183], and the Resilient Power Project (U.S.)[184].
- NYSERDA, *Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State*, 2010, "Microgrid Ownership and Service Models", pp. 22–29, provides a detailed discussion of multiple ownership and service types. Appendix A provides detailed case studies of six microgrid projects in the U.S and the UK.

DER costs. DER cost data is discussed in section B4.2.

[182] ILSR, *Mighty Microgrids*, 2016, p. 11.
[183] https://building-microgrid.lbl.gov/examples-microgrids
[184] http://www.cleanegroup.org/ceg-projects/resilient-power-project/featured-installations/

Figure B-14: EIA Generator Costs (I)

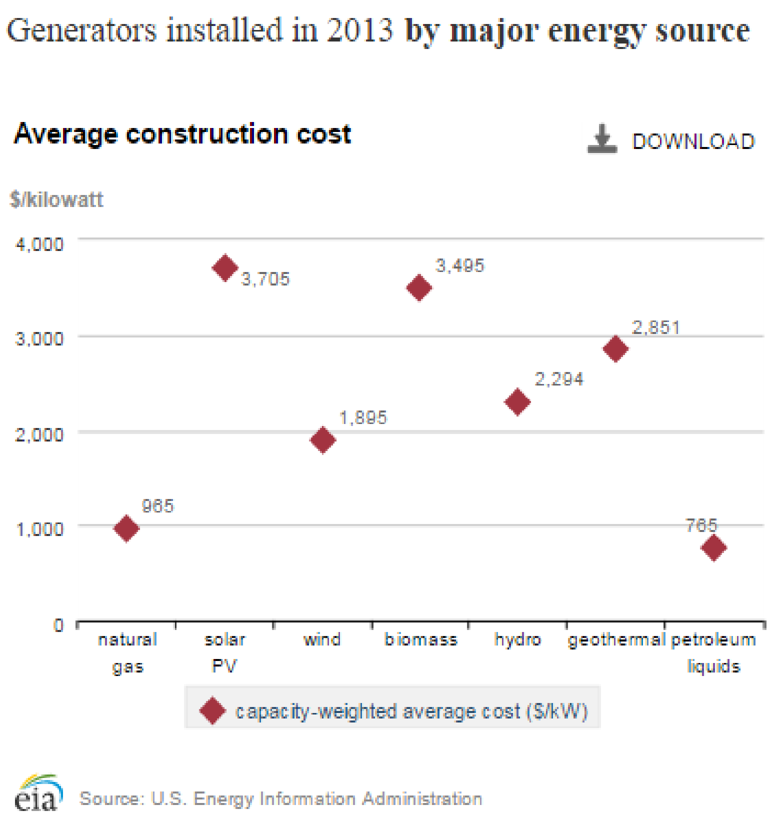


Figure B-15: EIA Generator Costs (II)

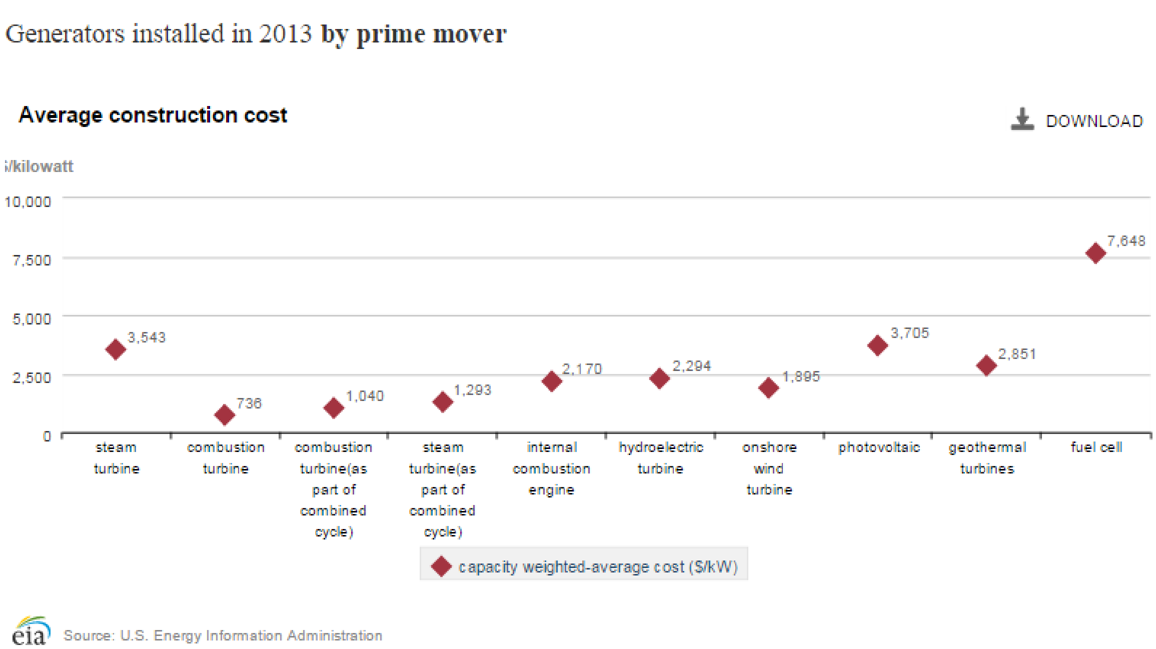
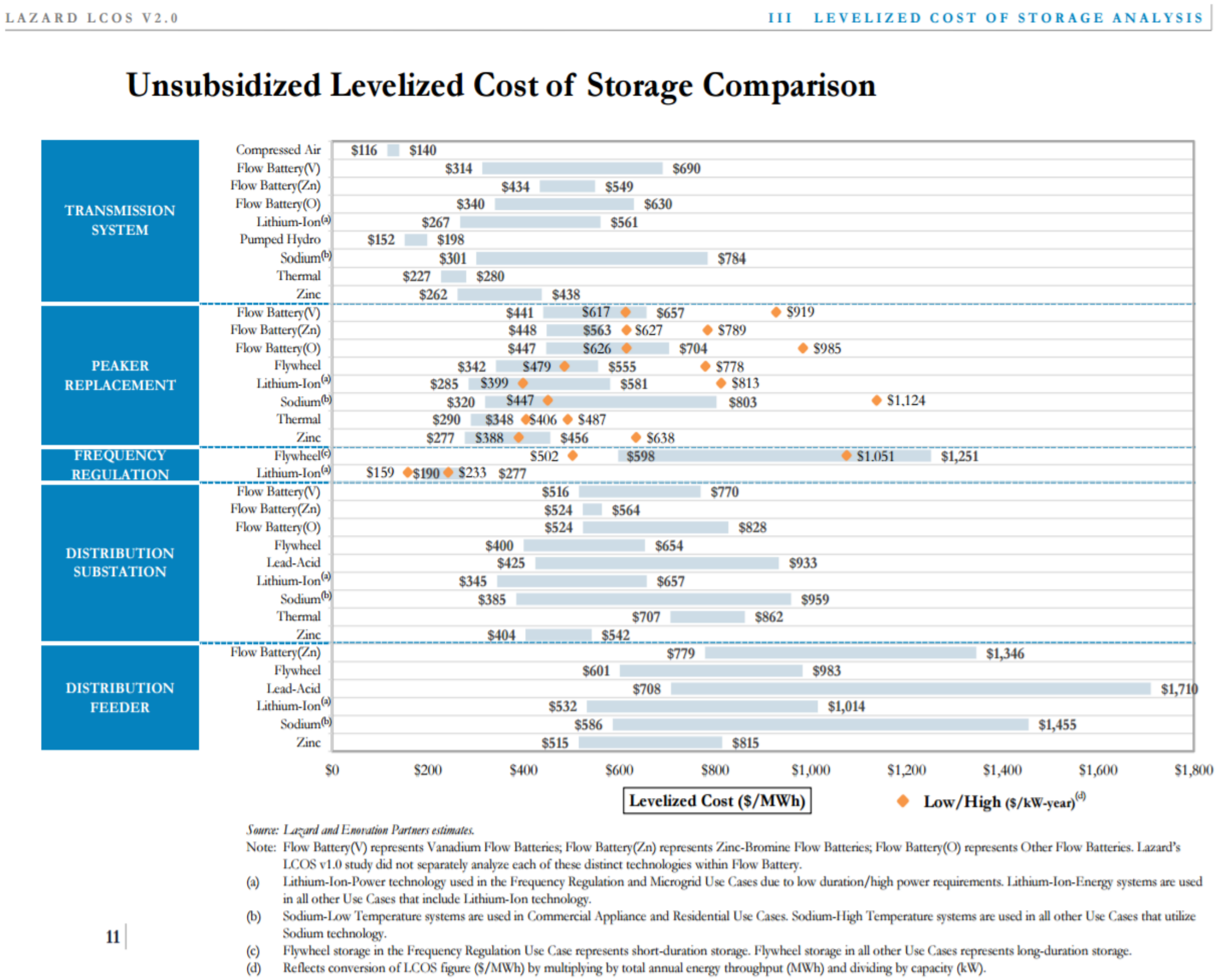


Figure B-16: Energy Storage Costs



Controls cost. "[C]ustom control solutions easily take up 30 to 50 percent of the microgrid cost, according to Bob Lassater, a microgrid researcher at the University of Wisconsin."[185] The NJ BPU estimated islanding equipment costs (controls + Point of Common Coupling) for new facilities as a "relatively small incremental portion of overall DER system cost. If designed and installed as a retrofit to an existing facility the costs can be greater in the 10% to 30% range. For retrofitting energy resiliency into an existing facility, the DER equipment must be upgraded to island mode and a significant portion of the existing electrical and interconnection systems must also be redesigned."[186]

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185 ILSR, *Mighty Microgrids*, 2016, p. 27.
186 NJBRU 2016, p. 29.

Figure B-17: Microgrid Controls & Infrastructure Costs (5 MW Installation)[187]

Table 7-1: Range of Costs for Microgrid Components

Qty	Microgrid Equipment	Description 5 MW Multi-DER Installation	Range Low	Range High
Microgrid Isolation and Stability Controls				
1	Main transfer switch	Disconnect when out of tolerance. Required for islanding.	$50,000	$100,000
1	Master controller	Microgrid stability controller[1]	$150,000	$500,000
1	Switchgear	Generation switchgear and controls (basic)[2]	$100,000	$400,000
Distribution Automation (2 circuits: non-interruptible + critical load and, non-critical load)				
2	Sectionalizing switchgear	Sectionalize non-interruptible and critical load from total load	$100,000	$200,000
1	Remote switchgear control	Master station for remote load shedding and distribution switchgear operation	$70,000	$110,000
1	Automatic fault protection	Relaying, protection and control equipment to enable switchgear to automatically detect and isolate fault.	$60,000	$125,000
5	Smart meters[17]	Includes data warehousing	$50,000	$100,000
Communication infrastructure				
1	Costs from smart-grid enabled substation communication infrastructure up to the point of common coupling, i.e. the utility transformer.		$500,000	$1,000,000
Total			**$1,080,000**	**$2,535,000**

[1] SCADA/EMS (forecasting, load-shedding, scheduling, optimization, market participation, resynchronization, islanding transitions, automated protection settings etc.) to monitor and manage power system from PCC to building circuit panels.

10. <u>Alternatives to microgrids</u>

A microgrids is a means to an end, but not an end in itself. Microgrids can facilitate a constellation of benefits and provide a range of solutions, but other approaches can also achieve the same goals.

Critical mission assurance. Some critical missions are facility-dependent, such as wastewater treatment. Other critical missions are performed by assets and organizations that can be relocated and continue to function, *e.g.*, first responders in emergency vehicles. Mobile assets should verify that if they leave their home base facility, they are going to a new host location that (1) enables them to fulfill their mission (*e.g.*, is not too far from the population to be served), and (2) that the new host facility has equivalent or superior energy assurance to their home base.

[187] MA 2014, p. 7-3.

Least-cost energy assurance – Single vs. multiple facility microgrids. Facility-dependent critical mission owners should evaluate assess their energy assurance options, including the cost of Level 1 *vs*. Level 2 microgrids. Microgrids can provide economic benefits, but it can be expensive to connect shared DERs to multiple facilities that are not close to each other. The costs per yard or mile of installing hazard-hardened wires and pipes (especially underground) can be very significant. Microgrid developers should total the costs of connecting a single DER location to two or more dispersed facilities, and compare it to the cost of installing equivalent DER capacity at each of those facilities. The greater the distance between two or more facilities, the greater the probability that forming two or more Level 1 single-facility BTM microgrids will be less expensive than forming one Level 2 multi-facility campus microgrid.

Least-cost energy assurance – Constant-duty DERs vs. BUGs. Facility-dependent critical mission owners should evaluate assess their energy assurance options, including Level 1 and Level 2 microgrids with constant-duty DERs, but also enhanced standby BUG capacity. Although constant-duty DERs can provide multiple benefits to enhance their economic performance, their cost-effectiveness can be highly case-specific. Some site characteristics are not conducive to economical DER retrofits that provide enough energy to serve critical loads with desired duration or reliability. Some critical facilities might find that they get greater energy assurance “bang for their buck” (and risk profile) by enhancing backup power capacity. Options include larger BUGs; dual-fuel BUGs to reduce the risk of supply disruptions; and installing infrastructure to enable mobile BUGs to plug-in to the facility, which could avoid purchasing onsite generation capacity and instead rely on plans to lease a BUG when needed. This strategy can be helpful with reducing the risks of hazards with an advance warning period (*e.g.*, large storms), but is of lesser value mitigating the risks of surprise disruptions.

PART C: COST/BENEFIT ANALYSIS OF RHODE ISLAND CRITICAL INFRASTRUCTURE MICROGRIDS

<u>Development of a microgrid cost-benefit analysis framework</u>

An OER microgrid program needs a standardized cost-benefit analysis (CBA) framework to help compare projects on an equivalent basis and allocate finite resources, and this report is tasked with recommending a methodology. See Section A2 for further discussion of critical facility prioritization.

Each microgrid will have project-specific features that shape the CBA, including ownership structure, procurement strategy and investment vehicle(s), sources of supplemental funding, operating modes, and other considerations. The CBA framework should utilize standard "microeconomic" financial methods and metrics used in energy and facility capital investment projects, to help align the program with the marketplace. In addition, OER wants to consider "macroeconomic" costs and benefits that extend beyond the project to affect the grid, society, the economy and the environment. (This perspective assumes the microgrid project owner is not the utility; if the EDC owns or invests in a microgrid, then transmission and distribution system costs and benefits could be considered "microeconomic." See section D2 for further discussion.)

Some macroeconomic aspects are easier to quantify than others. There is no national standard approach to evaluation of these types of factors, although precedents and reference voluntary standards exist, including a well-developed set of conversion factors in the NY Prize microgrid program CBA tool[188]. RI is developing its own applicable methods, *e.g.*, in the Lowest Cost Procurement and Non-Wires Alternatives approach, and Docket 4600 Total Resource Cost Test.

The authors provide OER with a rough model Cost-Benefit Analysis Model (CBAM) tool that focuses on metrics which support project investment (see section C2). Microeconomic factors are primary. Macro-economic factors are secondary and complementary, and are not included in our spreadsheet. As discussed in section A2, there are two primary options for a programmatic approach to quantifying macroeconomic factors, which we describe below as "Economic Valuation" and "Point Scoring" methods.

Economic Valuation method. Macroeconomic factors could be assigned monetary value using reference criteria such as are contained in Docket 4600's Total Resource Cost Test, or the NY Prize CBA tool.[189] This approach provides more objective, precise (if not accurate) information that can be integrated with "microeconomic" analysis using a dollar value common denominator. Valuation of program goals in dollar terms can be complex and more subjective, *e.g.*, the added

[188] https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize
[189] See "NY Prize Community Microgrid Benefit-Cost Analysis Information" section and links at: https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize/Resources-for-applicants

value when a microgrid serves a low to moderate income demographic. Developing this detailed analysis is more resource-intensive for both the program and its participants. If this approach is taken, OER should provide a detailed template and guidance for applicants to apply appropriate conversion factors, and/or support applicant CBA with funding or technical assistance teams.

The NY Prize program provided up to $100,000 in Stage 1 funding to each of 83 feasibility studies for community microgrid projects in identified "opportunity zones" of high potential value to the grid. In March 2017 the program announced Stage 2 funding awards of approximately $1 million each to 11 microgrid projects.[190] The program conducted analysis from a societal point of view and developed a tool to quantify costs and benefits to the Electric Power System (EPS) and society. Their tool provides a template with conversion factors for economic valuation estimates such as benefits from outage avoidance, power quality improvements, etc. Valuation methods were drawn from sources including research from the U.S. Department of Energy's Lawrence Berkeley National Laboratories (LBNL), the Electric Power Research Institute (EPRI) and others. See Section A2 for further discussion.

This feasibility analysis approach provides a more comprehensive picture of microgrid benefits, yet also involves a high level of effort and detailed data collection. NY Prize feasibility study funding assistance is roughly twice the amount per project of other programs (*e.g.*, CT, MA). Note that the NY Prize projects generally involve Level 3 community-scale multi-user microgrids that are more complex and involve more critical facilities than the Level 1 and Level 2 microgrids prevalent in CT and MA programs. NY Prize is occurring in the context of NY's comprehensive Reforming the Energy Vision (REV[191]) proceedings that are reconsidering the full spectrum of electricity policy and utility regulation. This difference from the RI context is a primary reason the authors recommend that OER use the streamlined Point Scoring approach.

A common question vexes energy assurance and emergency preparedness planners: What is the value of resilience? The Economic Valuation method attempts to put a dollar value on the answer, at least in the microgrid context.

Point Scoring method. A streamlined scoring process with abstracted values representing macroeconomic factors and program preferences could simplify evaluation of funding applications. This approach provides information that is more subjective and less accurate, precise and detailed than the Economic Valuation method, and cannot be integrated with "microeconomic" analysis in monetary terms but rather is used in parallel. This abstracted analysis is less resource-intensive for the program and its participants. If this approach is taken, OER could score funding applications based on information provided in the applications.

[190] See "View All Stage 2 Awarded Projects" tab at: https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize/Opportunity-Zones-Map
[191] https://rev.ny.gov/

<u>Policy recommendation</u>: An OER microgrid program could develop a tool similar to (but more refined than) the author's spreadsheet-based CBAM tool, complemented by the Point Scoring method to simplify the process and conserve program and project resources. The authors suggest a scoring template in Table C-1, which OER can modify as desired.

Table C-1a: Critical facility energy scoring factors

CRITERION	RANGE	FACTOR	POINTS	NOTES
CHP or renewable energy	0–4	1 point per 25% of peak critical load served by (equivalent DER capacity = [rated kW x 0.8 x capacity factor])	0–4	
Duel fuel capability	0–2	1 point per 50% of peak critical load served by (equivalent DER capacity = [rated kW x 0.8 x capacity factor])	0–2	
Onsite fuel storage 1 week	0	Prerequisite	0	
Onsite fuel storage >1 week	0–2	1 point per 50% of peak critical load served by (equivalent DER capacity = [rated kW x 0.8 x capacity factor])	0–2	
2 weeks fuel stored in municipal boundary under microgrid owner control	0	Prerequisite	0	
>2 weeks fuel stored in municipal boundary under microgrid owner control	1	Credit	1	

Table C-1b: Critical facility scoring factors

CRITERION	RANGE	FACTOR	POINTS	NOTES
Criticality	1–3	Unique Asset	3	Do not include if there is separate UA track
		Lifeline Sector CF	2	
		Priority CF in sector (SLA- or SSP-designated)	2	
		CF community mission	2	
		CF serves occupants or residents	1	
Number of critical facilities		(Criticality points per CF) x (n = # of CFs)	(1–3) x n	
Population served	1+	<1,000 people served	0	CF occupants for SIP
		1,000–10,000 people served	1	Population served by critical mission (*e.g.*, emergency services call area, municipal boundary, connected customers)
		Per 10,000 people served over 10,000	1	
		Unique Asset	20	Do not include if there is separate UA track
Year around operational capability	0	Prerequisite	0	Maintain interior temps in critical mission areas between 35°F–85°F for healthy adults, 45°F–80°F for minors and seniors, maintain critical equipment temp requirements
Microgrid ability to withstand Cat 1 hurricane	0	Prerequisite	0	
Can withstand Cat 2 hurricane	1		1	
Microgrid ability to withstand Cat 3+ hurricane	1		1	
E-threat protection	1		1	Measures TBD (shielding)
Cybersecurity protection	1		1	NIST standards implemented
Physical protection	1		1	Restricted access

Policy recommendation: If OER prefers to use the Economic Evaluation method, the program should use the NY Prize CBA template, and where applicable modify the conversion factors to use Docket 4600 or other state-specific approaches. OER should provide applicants with a detailed CBA template and instructions, as well as feasibility analysis funding and/or technical support sufficient to the task.

Cost-Benefit Analysis Model (CBAM) tool

2.1 Introduction

The author's Cost-Benefit Analysis Model (CBAM) tool was based on the CBA tool developed for the NY Prize microgrid program.[192] The CBAM tool is attached to this report as a template spreadsheet tool, for OER use only. This tool is not for public use, and is provided to OER to serve as a conceptual template for development of a comparable but more complex and refined tool, similar to that used in NY Prize; development of such a finished tool is beyond the scope of this report. The CBAM tool provides information that can be used to develop a microgrid project *pro forma* as part of a funding application, similar to that employed by the CT DEEP microgrid funding program Round 3 RFP,[193] which the authors recommend as an OER program application template.

See Section E for case study applications of the CBAM to pilot project candidate facilities. The authors used Hybrid Optimization of Multiple Energy Resources (HOMER) Pro 3.8.4 version software to evaluate Distributed Energy Resource (DER) options for the two pilot projects. HOMER is a microgrid analysis tool developed by the U.S. National Renewable Energy Laboratory (NREL). It allows modeling of various microgrid technologies to determine the lowest cost of energy solution given a number of inputs, including information about the resources generating electricity and the facilities whose loads are served. HOMER is not required; any source of design that predicts microgrid DER output on a monthly basis will suffice. Two similar programs are RETScreen Clean Energy Management Software[194] and LBNL's Distributed Energy Resources Customer Adoption Model (DER-CAM)[195] tool.

2.2. CBAM tool overview

The Cost-Benefit Analysis Model (CBAM) was developed using an Excel-based tool. The costs and benefits are calculated from the perspective of the microgrid owner, who is assumed to also

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[192] See "NY Prize Community Microgrid Benefit-Cost Analysis Information" section and links at: https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize/Resources-for-applicants
[193] http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/69dc4ebaa1ebe96285257ed70064d53c?OpenDocument
[194] http://www.nrcan.gc.ca/energy/software-tools/7465
[195] https://building-microgrid.lbl.gov/projects/der-cam and https://eetd.lbl.gov/software/389/der-cam

be the electricity customer. There is a long list of benefits associated with a microgrid, but this tool is limited to the costs and benefits directly related to the generation and purchase of electricity. However, CBAM allows for the input of additional benefits whose value has been estimated outside of this tool.

The analysis takes place anytime between the years of 2016 and 2050, for a maximum period of 35 years. This enables tool users to evaluate microgrid project economic performance over time periods that align with preferred analytical parameters, *e.g.*, 20- or 25-year Net Present Value (NPV) or procurement contract terms such as a 15- to 25-year Energy Savings Performance Contract (ESPC), Power Purchase Agreement (PPA) or Energy Services Agreement (ESA). Inflation and taxes are not considered. An input discount rate is used to calculate the net present value (NPV) of all benefits and costs. It also creates an annuity from the NPV to assess annual value. The user may choose to include escalation of energy prices using Energy Information Administration (EIA) price forecasts. There are options to use forecasts including or excluding the USEPA Clean Power Plan, or to exclude escalation. The tool allows for up to ten facilities and ten Distributed Energy Resources (DERs).

Inputs

Table C-2: CBAM inputs

Model parameters	Analysis period, discount rate
Baseline information	Monthly electricity consumption (kWh), electricity demand (kW), and thermal fuel purchases (MMBtu), and utility rates for electricity and fuel
Power and thermal Generation	DER and CHP sizing, fuel consumption, fuel price, compensation, and monthly production
Costs	Capital, fixed O&M, variable O&M for each component, additional costs
Benefits	Compensation scheme for each DER/CHP, additional benefits
Efficiency	Reduction in electrical and thermal loads, costs to implement

Outputs

- NPV and annualized value of all costs and benefits
- Levelized Cost of Energy (LCOE)
- Benefit-Cost Ratio
- Simple Payback
- Internal Rate of Return
- Year 1 Grant Requirement (see Section C2.3)

Assumptions and Calculations

The model first takes the input baseline loads and reduces them by the input energy efficiency savings. The “energy efficiency savings” benefit is simply the magnitude of these reductions (in kWh or MMBtu) multiplied by the appropriate baseline utility prices. The remaining calculations for the microgrid's costs and benefits use this reduced load.

The reduced load and baseline utility electricity prices are used to calculate payments made to the utility. Independently, the electricity sales are calculated for each generating asset based on generation and input compensation scheme. There are two options for DER compensation: Option 1, or "not behind the meter," and Option 2, "behind the meter." Option 1 simply compensates the DER for every kWh generated at an input rate; this model can be used for long-term contracts, or for a feed-in-tariff. Option 2 is meant to model net metering, and ties the DER to a certain facility. If neither of these apply, use the "additional benefits" inputs to model revenue.

The production of thermal energy in excess of the load within the microgrid is not compensated. Calculations are broken down into fuel source to allow the escalation of energy prices using EIA forecasts, which are broken down by fuel source.

The LCOE is calculated as the net present cost of all costs and benefits related to the provision of energy divided by the total energy produced. These include all costs except for energy efficiency. Benefits included are CHP fuel cost savings, electricity sales revenue, and salvage value.

Grant Amount input can be used to assess potential grant amounts required to achieve a desired financial outcome. See Section C2.3 for further discussion.

When the first iteration of this spreadsheet was developed in October 2016, the price forecasts used for escalation made use of EIA 2015 Reference Cases, one with and one without the Clean Power Plan. Those cases included different price forecasts, so that choice had an impact on project economics. These were updated in early 2017 to the EIA 2016 Reference Cases, in which the two scenarios were still published, but are now nearly identical.
Because system sizing and monthly electricity production are inputs this tool requires, a preliminary design should take place prior to its use. The HOMER software was used in this case, but doesn't need to be. See Section C2.1 for further discussion.

<u>Model structure</u>

These are the basic model inputs, controlling the analysis period, discount rate, grant amount in year one, and price escalation scenario. They are found on the "Dashboard" tab.

Figure C-1: Model Parameter Inputs

Model Inputs

Analysis start year		
Analysis end year		
Analysis Period	0	Years
Discount rate		%
EIA Price Forecast: Choose scenario		
EIA Price Forecast: Choose sector		
Show Outputs For: Choose Option		
Funding Feasibility: Grant Amount		$

Color Key
Inputs
Outputs
Benefits
Costs
Calculations
Reference Data

Also on the "Dashboard" tab are the primary outputs, including net present and annualized values of benefits and costs, as well as energy produced. Cash flows are presented graphically.

Figure C-2: Model Financial and Energy Outputs

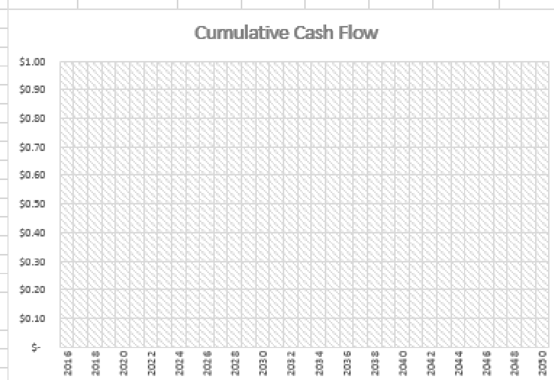
Key Outputs

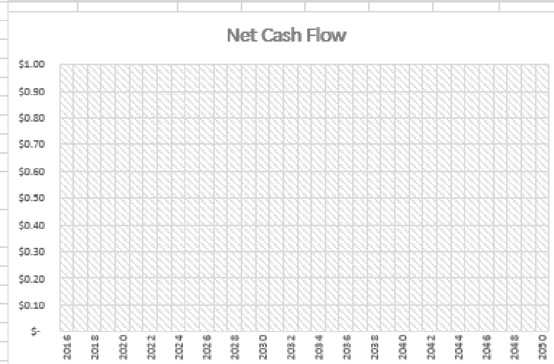
Financials		
Benefit-Cost Ratio		
Simple Payback		years
IRR		%
Project LCOE (with thermal gen.)		$/kWh
Project LCOE (electricity only)		$/kWh

Benefits		
Category	**Present Value**	**Annualized Value**
Avoided Boiler Fuel Purchases		
Electricity Sales Revenue		
Energy Efficiency Savings		
Additional Benefits		
Year 1 Grant		
Salvage Value		
TOTAL BENEFITS		

Costs		
Category	**Present Value**	**Annualized Value**
Design Costs		
Capital Investments		
Non-Fuel Fixed O & M		
Non-Fuel Variable O & M		
Additional Fuel Cost		
Boiler Fuel Cost		
Electricity Purchases		
Energy Efficiency Costs		
Additional Costs		
TOTAL COSTS (WITH UTILITY PURCHASES)		
TOTAL COSTS (WITHOUT UTILITY		

Energy		
Baseline Electricity Consumption		kWh/year
Reduced Electricity Consumption		kWh/year
Baseline Electricity Demand		Peak kW
Reduced Electricity Demand		Peak kW
Electricity Generated		kWh/year
Electricity Purchased		kWh/year
Excess Electricity		kWh/year
Baseline Thermal Load		MMBtu/year
Reduced Thermal Load		MMBtu/year
CHP Thermal Generation		MMBtu/year
Boiler Thermal Generation		MMBtu/year





These boxes on the "Baseline Inputs" tab are where baseline electricity consumption, electricity demand, and thermal fuel consumption are input from utility bills.

Figure C-3: Electric and Thermal Loads

	Electricity Consumption													
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM	YEAR AVE
Facility	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
SUM	0	0	0	0	0	0	0	0	0	0	0	0	0	0

	Electricity Demand												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM
Facility	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW
													0
													0
													0
													0
													0
													0
													0
													0
													0
													0
SUM	0	0	0	0	0	0	0	0	0	0	0	0	

	Thermal Fuel Purchases																
	Fuel Type	Fuel Cost	Boiler / Furnace Name	Boiler / Furnace Efficiency	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM
Facility		$/MMBtu		%	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu
																	669
																	0
																	0
																	0
																	0
																	0
																	0
																	0
																	0
																	0
SUM					0	0	0	0	0	0	0	0	0	0	0	0	0

Utility rates for electricity are input here for each facility. Also shown is a thermal fuel converter, included for convenience in conversion calculations.

Figure C-4: Electricity Rate Inputs

UTILITY ELECTRICITY RATES			
	Fixed Charges	Energy Charges	Demand Charges
Facility	$/month	$/kWh-mo.	$/kW-mo.
SUM			

REFERENCE HEATING UNIT CONVERTER			
	MMBtu	0.00	Btu
		0.0000	MMBtu
		0.00	kWh
		0.00	Therm
		0.00	Ccf Natural Gas

On the “Design Inputs” tab, information about generating assets, electrical and thermal generation, and energy efficiency is input.

Figure C-5: DER Information and Electrical Generation Inputs

GENERATING ASSETS

Electricity Generating Resources					
	Rated Power	Fuel Type	Fuel Consumption	Fuel Cost	Compensated for Overgeneration ?
Resource	kW		MMBtu/kWh	$/MMBtu	
SUM	0				

Combined Heat & Power Resources								
	Rated Power	Fuel Type	Fuel Consumption	Fuel Cost	Compensated for	Maximum Thermal	Associated Facility:	Offset Fuel From:
Resource	kW		MMBtu/kWh	$/MMBtu		MMBtu/hr		
SUM	0							

ELECTRICAL GENERATION

	Electricity Generation												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM
Resource	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	
													0
													0
													0
													0
													0
													0
													0
													0
													0
													0
SUM	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure C-6: Thermal Generation and Energy Efficiency Inputs

THERMAL GENERATION

	CHP Thermal Generation												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM
Resource	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	
													0
													0
													0
													0
													0
													0
													0
													0
													0
													0
SUM	0	0	0	0	0	0	0	0	0	0	0	0	0

ENERGY EFFICIENCY

ENERGY EFFICIENCY UPGRADES							
Facility	Reduction of Energy Demand	Reduction of Energy Usage	Reduction of Heating Demand	Offset Fuel From:	Efficiency Capital Cost	Efficiency O&M Cost	Description of ECM Package
	kW/month	kWh/month	MMBtu/month		$	$/Year	
SUM	0	0	0		$ -	$ -	

Also on “Design Inputs” is the space to input all capital, fixed O&M, variable O&M, design, and additional costs. Below that, compensation schemes for generating assets are input, along with any benefits not captured elsewhere.

Figure C-7: Cost Inputs

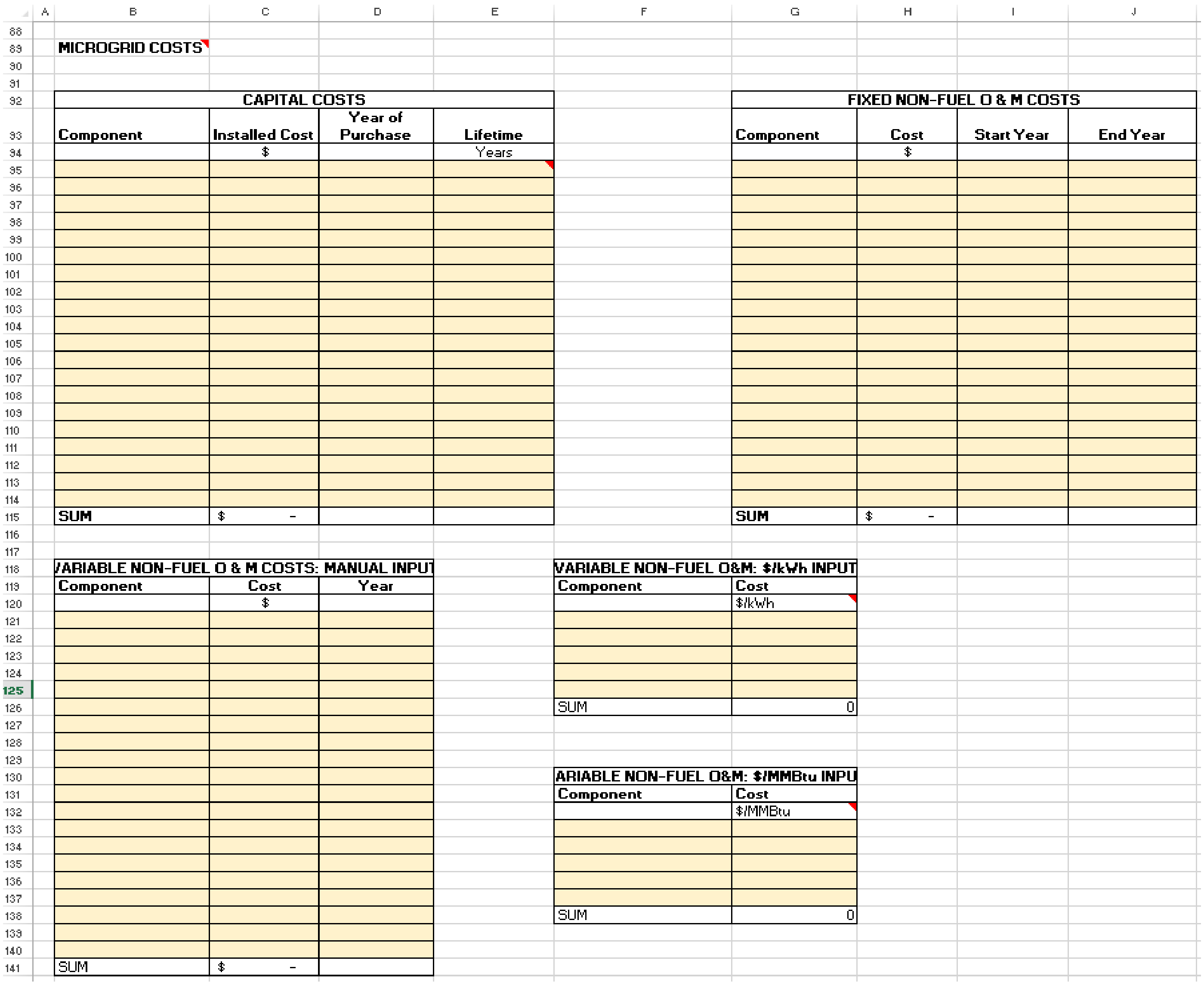


Figure C-8: Benefits inputs

ADDITIONAL ONE-TIME COSTS			
Component	Cost	Year	Description
SUM	$ -		

DESIGN COSTS	
Component	Cost
	$

ADDITIONAL ONGOING COSTS				
Component	Cost	Start Year	End Year	Description
SUM	$ -			

MICROGRID BENEFITS

COMPENSATION FOR OVERGENER		Option 1: Not Behind the Meter		Option 2: Behind the Meter							
Generating Resourc	Revenue Mode	Fixed Payments	Energy Payments	Associated Facility	Price Tier 1: Max % Load	Fixed Payments	Energy Payments	Price Tier 2: Max % Load	Fixed payments	Energy Payments
		$/month	$/kWh		%	$/month	$/kWh	%	$/month	$/kWh
SUM		$ -	$ -							

ADDITIONAL ONE-TIME BENEFITS			
Component	Benefit	Year	Description
SUM	0		

ADDITIONAL YEARLY BENEFITS				
Component	Benefit	Start Year	End Year	Description
SUM	0			

2.3. Using the CBAM tool to determine potential funding awards

The "Grant Amount" input space can be used to assess potential grant amounts required to achieve a desired financial outcome. OER could apply one or more different funding strategies; options are described below regarding CBAM applications.

Eligible equipment. OER could award grants based on eligible equipment. This categorical equipment-based approach has the advantages of being consistent and equitable in application, and the potential disadvantage that the grant amount might not be sufficient to ensure project gets financed and built. OER microgrid program managers could request cost information about funding-eligible equipment in applications, then have the applicant enter the equivalent installed cost in this cell of the CBAM. This would determine the grant impact on project CBA.

For example, the CT microgrid program takes this approach. Rounds 1 and 2 funded only electrical infrastructure such as circuits/wires, transformers, switchgear, point of common coupling, controls, etc. but did not fund generation; Round 3 of the program allows funding to be applied to generation and energy storage. Funding a microgrid's electrical architecture but not its generation is reasonable, because the former does not directly produce cost savings or revenue (although controls can enable cost-optimal operation and revenue opportunities) while the latter can reduce costs and is eligible for a variety of other distributed generation economic support (*e.g.*, tax credits, per-kW incentives, feed-in tariffs).

Capital contribution. OER could seek to maximize the leverage of its finite funding by contributing capital to a microgrid project sufficient to enable it to be financed by an applicant-designated procurement model or investment vehicle (*e.g.*, 25 year term ESA, 20 year C-PACE assessment, or 15 year ESPC). This approach has the potential advantage of conserving program funds in cases where a modest contribution could spur project financing and leverage private investment, perhaps at lower program expenditure than an equipment-based approach. It has the disadvantages of inconsistency and potential inequity in application among various candidate projects, as well as case-by-case, microgrid project- and owner-specific financial criteria such as acceptable and available simple payback (SPB) periods. Award criteria parameters could improve consistency and equity, such as a funding cap of "X" dollars per kW of microgrid generation. (The CT program cap is $7,000/kW and $3 million per project.) Apparently, no other state has taken this contribution approach.

For example, a hypothetical retrofit combined heat and power (CHP) microgrid project submits a funding application that has a $3 million capital cost, is projected to lower facility costs by $100,000 annually, and has a 30-year SPB period (*i.e.*, $100,000 x 30 years = $3 million). (We will ignore interest and tax effects for simplicity.) The project owner seeks $1.5 million in funding for (eligible) equipment. Alternately, a $1 million program capital contribution could reduce initial project costs to $2 million, maintain the level of savings at $100,000/year, and shorten the simple payback period to 20 years (*i.e.*, $100,000 x 20 years = $2 million). This shorter SPB period could enable the project to be financed via a 20-year-term investment vehicle such as an Energy Savings Performance Contract (ESPC) or Power Purchase Agreement (PPA). In this case OER could enable the project to be financed and constructed for $1 million versus $1.5 million, a savings of $500,000.

OER program administrators could use the "Grant Amount" input cell (cell C15 on the "Dashboard" tab) on an applicant project's CBAM for an iterative trial-and-error to assess the effects of awarding a grant of the input funding amount in Year One. Model outputs and cash flow diagrams are directly below that cell; grant impacts can be easily assessed by adjusting the "Grant Amount" cell and assessing effects.

Credit Enhancement. OER could use program funds to buy down the interest rate on a third-party financing to enable a microgrid project to get a loan on acceptable terms. This approach has the advantage of potentially conserving program funds and leveraging private investment. It has the disadvantage of potential inconsistency and inequity due to case-by-case, microgrid project- and owner-specific financial criteria and ability to get a loan. Institutions such as the CT Green Bank offer this type of approach to support energy and microgrid projects.

Policy recommendation: OER should use the Eligible Equipment method to simplify program administration and foster consistency and equity in funding awards. Eligible equipment grants should exclude generation, but include energy storage and electrical infrastructure. Reference the CT microgrid program electrical equipment list,[196] but make eligible facility internal rewiring to enable critical load circuit modifications and load shedding.

OER should consider also providing applicants with the option to request Capital Contribution and Credit Enhancement awards, which would be evaluated on an equivalent basis with Eligible Equipment applications (*e.g.*, dollars per project or $/kW of DER capacity). This would provide an incentive to applicants to leverage non-program funds such as private investment, because smaller grant requests would be assessed more favorably.

[196] See list in CT DEEP *Final Round 3 Application Instructions*, Part E-1, pp. 9–10, accessed at: http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/69dc4ebaa1ebe96285257ed70064d53c?OpenDocument

PART D: MICROGRID PROGRAM AND POLICY RECOMMENDATIONS

<u>Microgrid policies and programs in other jurisdictions</u>

1.1. Overview

This Section briefly describes state microgrid programs in CA, CT, MA, NJ and NY.

CA, CT and MA programs are broadly similar in structure, with CA funding a smaller number of microgrid projects (7) than CT (11) and MA (21), mostly Level 1 single facility or Level 2 campus microgrids. Each state issued solicitations for grant funding applications for microgrid projects. NJ provided funding for DERs at scores of municipal critical facilities, and its Energy Resilience Bank has a program to fund Level 1 microgrids at wastewater treatment facilities and hospitals.

Some states are working on the bigger picture barriers and opportunities surrounding Level 3 multi-user community microgrids. Both the NJ Town Center DER project and the NY Prize program are working to develop pathways to Level 3 multi-user community microgrids. CA is developing a microgrids roadmap. The MA Clean Energy Center (MA CEC) and Boston Redevelopment Authority (BRA) have conducted research and tool development aimed at fostering Level 3 microgrids. Research and policy deliberations underway in Maryland[197] (in particular) and Minnesota[198] (less so) are also grappling with these issues. But only in NY and to a lesser degree MD (and arguably in CA) is this effort occurring in the context of a comprehensive rethinking of traditional utility regulation. See D2.2 for further discussion.

1.2. California: Microgrid policy development and demonstration funding

CA has a broad range of microgrid-related activities underway, with a moderate degree of centralized coordination in the California Energy Commission (CA CEC) which provides funding and policy development, and the California Public Utilities Commission (CPUC) with

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[197] See *Maryland Resiliency Through Microgrids Task Force Report* at: http://energy.maryland.gov/documents/MarylandResiliencyThroughMicrogridsTaskForceReport_000.pdf
[198] See *Minnesota Microgrids: Barriers, Opportunities, and Pathways Toward Energy Assurance* at: http://mn.gov/commerce-stat/pdfs/microgrid.pdf

policy development. In 2014 the CPUC released a white paper titled *Microgrids: A Regulatory Perspective*.[199]

In 2014–2015 the CA CEC conducted solicitation PON-14-301 *Demonstrating Secure, Reliable Microgrids and Grid-Linked Electric Vehicles to Build Resilient, Low-Carbon Facilities and Communities* and awarded $21.8 million for 7 microgrid projects, with a mix of Level 1 and Level 2 microgrids.[200] In 2016 the CA CEC's Electric Program Investment Charge (EPIC) Challenge awarded the City of Santa Monica $1.5 million to study barriers to development of a Level 3 multi-user community microgrid based around a Level 2 municipal critical facility campus microgrid, and to recommend implementation strategies.[201] The CA CEC funded a 2015 study by DNV titled *Microgrid Assessments and Recommendations to Guide Future Investment*,[202] and is currently developing a microgrid roadmap, including a series of multi-stakeholder workshops.

In 2014 the City and County of San Francisco and a consultant team led by Arup received a DOE Solar Market Pathways grant to plan "solar plus storage" Level 1 microgrids for critical facility resilience citywide, and to develop a national planning guide for municipalities. The City of Berkeley is also developing a solar plus storage critical facility Level 2 urban campus microgrid.

1.3. Connecticut: CT DEEP microgrid grants and loans program

In 2011–2012 CT established a Two Storms panel in the wake of statewide week-plus outages after each Hurricane Irene and Storm Alfred (the "Halloween Nor'Easter") in 2011. The panel recommendations included establishing the nation's first microgrid program, with a high degree of centralized coordination by the CT Department of Energy and Environmental Protection (DEEP).

Starting in 2012, the DEEP microgrid program provided over $45 million of state bond funding for three rounds of solicitations for projects that comprise two or more separately metered facilities. Funding is awarded on an Eligible Equipment basis for microgrid electrical infrastructure; generation and energy storage were excluded in the first two rounds but are eligible for funding in Round 3. In Rounds 1 and 2[203] CT reimbursed up to $50,000–$60,000 of project engineering costs in award recipients, which could include some feasibility assessment expenditures.

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[199] www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5118
[200] https://microgridknowledge.com/california-awards-27-3m-demonstrate-microgrids-ev-charging/
[201] https://microgridknowledge.com/advanced-microgrid-santa-monica/
[202] http://www.energy.ca.gov/2015publications/CEC-500-2015-071/CEC-500-2015-071.pdf
[203] See "Microgrid Grant and Loan Pilot Program" and "Microgrid Grant Program – Round 2" links at: http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=7&Count=30&Collapse=24&Seq=9

The first two rounds funded 11 projects, all of which were effectively Level 2 campus microgrids; three of these are operating as of March 2017 with a further one or two close to operational status. Round 3[204] continues with rolling applications, a cap of $3 million per project or $7,000 per kW, plus an additional $2 million available for projects in USDA priority areas.

Table D-1: CT DEEP microgrid program Round 1 awards[205]

Project	Facilities	Generation	Grant Value
UConn Depot Campus/Storrs	Campus Buildings	400 kW fuel cell, 6.6 kW PV	$2,144,234
City of Bridgeport-City Hall/Bridgeport	City hall, Police Station, Senior Center	(3) 600 kW natural gas microturbines	$2,975,000
Wesleyan/Middletown	Campus, Athletic Center (Public Shelter)	(1) 2.4 MW and (1) 676 kW Natural Gas Combined Heat and Power Reciprocating Engine	$693,819
University of Hartford-St. Francis/Hartford	Dorms, Campus Center, Operation Building	(2) 1.9 MW diesel (existing), 250 kW diesel, 150 kW diesel	$2,270,333
SUBASE/Groton	Various Buildings and Piers	5 MW cogen turbine, 1.5 MW diesel	$3,000,000
Town of Windham/Windham	2 Schools (Various Public Purposes)	(2) 130 kW natural gas, 250 kW solar, 200 kWh battery; (2) kW diesel,	$639,950
Town of Woodbridge/Woodbridge	Police Stations, Fire Station, Department of Public Works, Town Hall, High School, Library	1.6 MW natural gas, 400 kW fuel cell	$3,000,000
City of Hartford- Parkville Cluster/Hartford	School, Senior Center, Library, Supermarket, Gas station	600 kW natural gas	$2,063,000
Town of Fairfield- Public Safety/Fairfield	Police Station, Emergency Operations Center, Cell Tower, Fire Headquarters, Shelter	50 kw natural gas recip engine, 250 kW natural gas recip engine, 27 kW PV, 20 kW PV	$1,167,659

Table D-2: CT DEEP microgrid program Round 2 awards[206]

Microgrid Grant Program - Round 2

Award Winners

Applicant	Critical Facilities	Generation	Grant $ awarded
City of Milford	Parsons Complex, middle school, senior center, senior apts, city hall	(2) 148kW natural gas CHP units, 120KW PV, 100kW battery storage	$ 2,909,341.00
University of Bridgeport	campus buildings - dining hall, rec center, student center, 2 residential buildings as shelter, police station	1.4 MW fuel cell	$ 2,180,898.72
TOTAL GRANTS AWARDED			**$ 5,090,239.72**

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204 See "Microgrid Grant Program – Round 3" link at: http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Collapse=24&Seq=10

205 http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/40cb9336a459e06185257bb20052b8ff?OpenDocument

206 http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/49f55e6a1f85d46885257d6400690f48?OpenDocument

1.4. Massachusetts: MA DOER Community Clean Energy Resilience Initiative (CCERI)

MA microgrid activities have a moderate to high degree of centralized coordination by both the Massachusetts Department of Energy Resources (DOER) with funding and policy, and the Massachusetts Clean Energy Center (Mass CEC) with policy research and tool development. In 2014 the MA CEC funded KEMA to author a microgrid study entitled *Microgrids –Benefits, Models, Barriers and Suggested Policy Initiatives for the Commonwealth of Massachusetts*, and a study of real and perceived legal barriers to microgrid development by Harvard Law School titled *Massachusetts Microgrids: Overcoming Legal Obstacles*.[207]

Starting in 2014 DOER issued a $40 million Community Clean Energy Resiliency Initiative (CCERI[208]) grant program using Regional Greenhouse Gas Initiative (RGGI) and Clean Energy funds. DOER also provided both feasibility assessment grants and contracted technical assistance teams employing HOMER microgrid planning software and other feasibility analysis support. In 2014 DOER made 6 awards for $7 million including four Level 1 single-facility microgrids and two Level 2 campus microgrids. In 2015 DOER awarded a further $18 million to 15 critical facility projects including 13 Level 1 microgrids and two Level 2 microgrids.

Table D-3: MA DOER CCERI microgrid program awards[209]

Applicant	Project Title	Grant Amount	Applicant	Project Title	Grant Amount
Barnstable	Cogeneration Plant at Barnstable Intermediate School	$ 406,000	Holyoke	Resiliency at Holyoke Facilities - Fire HQ, Mt. Tom Tower, Dean School	$ 1,013,794
Berkley and Taunton	Berkley/Taunton Community Microgrid	$ 1,455,000	MAPC - Beverly	Energy Resiliency at Beverly Regional Cache Site	$ 526,180
Boston	Solar PV with Battery Storage for select Boston Community Centers	$ 1,320,000	MAPC - Wayland	The MAPC Solar Resiliency Project	$ 264,627
	BMC Menino Campus CHP Plant	$ 3,680,000	Medford	Medford Resiliency Project	$ 833,366
Cambridge	Cambridge Water Supply Resilience	$ 851,868	Northampton	Batteries and PV Islanding Capability for Fire HQ	$ 525,401
Chelmsford	McCarthy Middle School, Emergency Power Generation	$ 74,941		Microgrid with Island-able PV at Smith Vocational and Agricultural High School, Northampton DPW and Cooley Dickinson Hospital	$ 3,078,960
Cape & Vineyard Electric Cooperative	Dennis-Yarmouth High School Regional Shelter	$ 1,479,193	South Essex Sewerage District	Combined Heat and Power Facility	$ 700,000
Greater Lawrence Sanitary District	Organics to Energy Upgrade Project	$ 5,000,000	Springfield	Baystate Health Cogeneration Project	$ 2,790,099
Greenfield	Greenfield Resiliency Plan for High School	$ 367,310	Sterling	Implementing a Resiliency Plan through Clean Storage for a Municipal Microgrid	$ 1,463,194
Total					$ 25,829,933

[207] http://environment.law.harvard.edu/wp-content/uploads/2015/08/masschusetts-microgrids_overcoming-legal-obstacles.pdf
[208] http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/resiliency/resiliency-initiative.html
[209] http://www.mass.gov/eea/docs/doer/renewables/resiliency/resilency-poster-3-24-15.pdf

1.5. New Jersey: NJ Resiliency Bank, Town Center DER microgrids report, and more

NJ has a range of microgrid-related projects underway, with a moderate degree of centralized coordination and significant interagency collaboration.[210] In the wake of Superstorm Sandy in 2012, NJ used $200 million in HUD Community Development Block Grant-Disaster Relief (CDBG-DR) funds to establish the NJ Energy Resilience Bank (ERB),[211] a first-of-its-kind institution with a focus on grant and loan funding for islandable DERs (primarily CHP) at wastewater treatment plants (WWTPs) and hospitals. As of late 2016, ERB provided $65 million to 2 WWTPs and 2 hospitals, with 7–10 more facilities (mostly hospitals) under consideration for a further $135 million.[212]

In 2013 NJ established statewide critical facility energy resilience program. "A multi-agency team from the State [collaborated] with the U.S. Department of Energy (DOE) and the DOE's National Renewable Energy Laboratory (NREL) to comprehensively study the energy needs of critical facilities throughout the State, and to identify creative and cost-effective alternative energy solutions. In coordination with the Board of Public Utilities, NREL conducted a state-wide survey of public buildings and leveraged existing data and resources maintained by the State to inform a locally-tailored analysis of energy resilience and efficiency for local communities. To realize energy resilience projects, the State announced $25 million in [federal Hazard Mitigation Grant Program (HMGP)] Energy Allocations to municipalities, counties, and other critical facilities that can be used to support a variety of alternative energy solutions — including microgrids, solar power with battery back-up, and natural gas-powered emergency generators — technologies that will allow critical facilities to operate even if the power grid fails."[213] The funds were intended to enable "146 municipalities, counties and other government units to pursue creative and cost-effective alternatives to enhance statewide energy resilience…. The grant allocations… range up to $734,880".[214]

The NJ Board of Public Utilities (NJBPU) and ERB engaged the New Jersey Institute of Technology (NJIT) and the Regional Planning Association (RPA) to map 27 potential town center DER (TCDER) Level 2 campus and Level 3 multi-user microgrids in 19 municipalities in nine FEMA Superstorm Sandy designated counties. The study, *New Jersey Town Centers Distributed Energy Resource Microgrid Potential Report GIS Analysis*, was designed to be a first cut screening tool to identify municipalities that have a number of critical facilities in close

[210] For example, see: http://www.state.nj.us/dep/aqes/ormr-energy-resiliency.html
[211] http://www.njeda.com/erb/erb-(1)
[212] http://www.njspotlight.com/stories/16/09/28/nj-energy-resilience-bank-getting-ready-for-second-round-of-withdrawals/
[213] See "Energy Resilience at Critical Facilities throughout The State" at: http://www.state.nj.us/dep/aqes/ormr-energy-resiliency.html
[214] Adapted from: http://www.state.nj.us/governor/news/news/552013/approved/20131009a.html

proximity that are good candidates for DER microgrid technologies.[215] (The authors note that the business model to develop these projects is not specified and might not yet exist.)

USDOE has provided funding and other support to two independent efforts, the proposed City of Hoboken microgrid and NJ Transit microgrid projects.

1.6. New York: NY Prize

NY microgrid efforts are highly centralized in NYSERDA's NY Prize[216] program, with related policy development in the multi-stakeholder Reforming the Vision (REV[217]) process. In 2010 The New York State Energy Research and Development Authority (NYSERDA) issued a detailed report, *Microgrids: An Assessment of the Value, Opportunities, and Barriers to the Deployment in New York State*,[218] which defined microgrid ownership models, regulatory barriers, value streams and costs, and established a roadmap to develop microgrids.

In 2014 the NY Department of Public Service (NYDPS) issued a procedural order establishing the REV process, developed to answer the question of what changes should be made in the current regulatory, tariff, market design, and incentive structure in NY to better align utility interests with achieving the State's energy policies. The 2014 Staff REV report recommended a proposed platform to transform the NY electric industry for both the regulated and un-regulated participants. The REV process has 6 objectives: enhance customer knowledge of their energy bills; enhance market issues to leverage ratepayer's contribution; enhance system efficiency; enhance fuel and resource diversity; improve system reliability; and reduce carbon emissions.[219]

In the REV context and in the wake of Superstorm Sandy, NYSERDA established the NY Prize program to fund Level 3 community microgrid feasibility studies and installations in designated "opportunity zones" of greatest potential value to the EPS. In 2015 NYSERDA awarded 83 Stage 1 feasibility assessments of up to $100,000 each to communities partnered with both investor-owned and municipal utilities. "The Stage 1 feasibility assessments will be followed by a Stage 2 audit grade engineering financial and business plan and a Stage 3 microgrid build-out. The total budget is up to $40 million".[220] In 2017 the program announced Stage 2 funding awards of approximately $1 million each to 11 microgrid projects.[221] NY Prize conducted analysis from a societal point of view and developed a Cost Benefit Analysis (CBA) spreadsheet-based tool for applicants to quantify non-traditional costs and benefits to the EPS and society.[222]

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[215] NJBPU 2016, pp. 114–115; see www.bpu/reports.
[216] https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize
[217] https://rev.ny.gov/
[218] NYSERDA 2010
[219] This section is adapted from NJBPU 2016, p. 119.
[220] NJBPU 2014, p. 120.
[221] See "View All Stage 2 Awarded Projects" tab at: https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize/Opportunity-Zones-Map
[222] See "NY Prize Community Microgrid Benefit-Cost Analysis Information" section and links at: https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize/Resources-for-applicants

In 2014 NYSERDA issued its excellent detailed report *Microgrids for Critical Facility Resiliency*.[223] "The objective of the report was to assess the practical feasibility of establishing microgrids to enhance resiliency of facilities that provide public safety, health and security support when the grid is down. The major findings were under most situations under current regulatory structures microgrids for critical infrastructure is usually not feasible or cost as effective as a backup system. The cost effectiveness improves if the facility is operated more frequently rather than just as a backup. There is a lack of information on developing microgrids and local governments have constraints and implements to implementing microgrids without funding support."[224]

For Further Reading:

- For a recent concise yet detailed overview, see the NJBPU 2016 report, pp. 116–121.
- A more detailed if slightly older overview can be found in Resilient Power Project / Clean Energy Group's 2015 report *What States Should Do: A Guide to Resilient Power Programs and Policy,* pp. 9–20.[225]

Policy recommendation: Many of the more complex successful microgrids were built in phases, such as the University of California - San Diego campus microgrid.[226] OER should take the same approach and develop microgrid programs and policies in phases.

The first phase is the primary focus of this report: a program aimed at helping public agencies and others conduct feasibility assessments of the potential for Level 1 single facility and Level 2 campus critical facility microgrids, with a competitive solicitation to identify and fund promising projects. OER should model this microgrid program on a hybrid of the CT and MA programs: follow the CT DEEP program structure, plus elements of the MA DOER CCERI program (particularly up-front feasibility assessment support and allowance of Level 1 single-facility microgrids). Complement the solicitation with a top-down effort to focus energy assurance support on uniquely critical assets, including liquid fuels terminals and gas stations. This program can be conducted in successive iterations with public feedback and other quality assurance in between funding "rounds" to facilitate programmatic learning and continuous improvements.

The second phase would evaluate the pros and cons of potential pathways to development of Level 3 multi-user community microgrids. This exploration should only occur in the context of a comprehensive review of energy policy and utility regulation akin to the NY REV process, and although microgrids can be one driver of this discussion, they should not be the primary motive.

[223] NYSERDA 2014.
[224] NJBPU 2014, pp. 119–120.
[225] http://www.cleanegroup.org/ceg-resources/resource/what-states-should-do-a-guide-to-resilient-power-programs-and-policy/
[226] https://building-microgrid.lbl.gov/ucsd

The RI energy policy community is undertaking numerous innovative and forward-thinking policy deliberations and implementation efforts, many of which share common elements and vision. But in the authors' humble opinion, a comprehensive framework and forum is lacking (although it might be emerging). Community-scale microgrid development could spur that discussion, but should not precede it. See section D2.2 for further discussion.

2. OER microgrid program design: Principles, goals and policy objectives

This section offers suggested microgrid program principles and policy objectives. It is the authors' intent to provide recommendations that conserve OER funds, foster market activity and mobilize private investment in support of RI energy and emergency planning goals. Program design will influence the type and extent of microgrid market activity. Some of the suggested principles reflect RI energy and resilience planning objectives; others address more generic program management best practices.

The policy discussion is structured with three types of program elements: administrative, legislative, and regulatory actions or measures. *Administrative* recommendations address actions that OER can implement under current conditions, without changing existing laws and regulations. *Legislative* recommendations address potential new laws or statutes that could support microgrid development, for example by mitigating a marketplace barrier or clarifying an area of legal uncertainty. *Regulatory* recommendations address potential actions that would require PUC involvement or decision, for example via a docket filing and ruling process. The regulatory category is intended to include issues that involve potential modifications to the fundamental elements of the existing regulatory compact with the regulated monopoly utility franchise in the "restructured" RI electricity sector, and to the current electricity distribution company business model. In practice the boundaries between these categories can be fuzzy and some recommendations could involve (for example) both the RI legislature and the PUC.

For the purposes of discussion, a microgrid combines Distributed Energy Resources (DERs) such as onsite power generation with controls and switchgear to enable both grid-connected and grid-independent facility operations. We will discuss these three program categories regarding the simplified typology suggested by the NJBPU[227]:

Microgrid type	DERs	Facilities	Meters	Facility owners
Level 1 single facility	1–2+	1	1	1
Level 2 campus	1–2+	2+	1–2+	1
Level 3 multi-user community	1–2+	2+	2+	2+

[227] NJBPU, *Microgrid Report*, 2016, p.17.

2.1. Principles to inform policy goals of program design

The 2015 *Rhode Island Thermal Working Group Report*[228] developed an excellent set of ten principles that are broadly applicable to other energy programs, including microgrids. We will excerpt those here and then discuss recommended microgrid program principles, some of which will be somewhat repetitive of the Thermal Working Group set.

"In considering policy and funding options, the Thermal Working Group developed a series of principles that should be considered as one weighs the merits and shortcomings of any approach:

1. "Funding streams should be **sustainable and sufficient** to meet the state's mandated goals.
2. "Funding levels should be **dynamic** to ramp up and down over time as needed.
3. "The level of funding should **balance short term costs with the benefits of providing long-term affordability** to all Rhode Islanders; mechanisms should be put in place to minimize financial impacts on low income Rhode Islanders.
4. "Funding sources, like program delivery, should be **equitable across non-electric fuels and by customer class** (residential, commercial, etc.); cross-subsidization between fuels and customer classes should be minimized; equitable treatment for instate and out-of-state fuel providers should also be addressed.
5. "Mechanisms that are **administratively efficient** to create and implement, simple, and auditable are preferred.
6. "The collection mechanism, sources, and uses of public funding must be **transparent**.
7. "**Price signals** should support state energy policy goals.
8. "Comprehensive delivered fuels energy efficiency programs should support the vibrancy of Rhode Island **communities and enhance competitiveness** of Rhode Island businesses.
9. "Public funding should be used to **leverage private sources of capital**, where possible, to get the best return on each public dollar invested.
10. "Public funding should be used **only to the extent that it is needed** to mobilize capital and meet private market shortcomings."[229] (*Original emphasis*.)

The following principles of program design are drawn from lessons learned by administrators of similar microgrid programs in other states, as well as other energy programs and general programmatic management best practices. These are intended to inform program design without foreknowledge or pre-judgement of inevitable constraints on the availability of key personnel, funds and time.

Design the program carefully with a multi-stakeholder team before roll out.

A state-administered microgrid program affects and involves numerous stakeholders, particularly where the program includes new legislative or regulatory elements.

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[228] http://www.energy.ri.gov/documents/Efficiency/Rhode_Island_Thermal_Working_Group_Report.pdf
[229] *Ibid*, pp. 13–14.

Employ an integrative design approach with the participation of key stakeholders from inception through implementation.

Integrative design methodologies such as architectural "charrette"-type intensive workshops are a proven approach to high-performance design outcomes in collective decision-making processes. An integrative approach to program design, for example via multi-stakeholder expert-facilitated program design workshops, can yield benefits including:

- Promote shared understanding and buy-in to program vision, goals and structure
- Clarify roles and responsibilities
- Develop a whole-systems view of the challenges and opportunities
- Identify opportunities for collaboration and synergies, as well as address potential conflicts and unintended consequences
- Foster innovation in program design by soliciting ideas with immediate feedback and discussion

An integrative, whole-systems approach to critical infrastructure protection would identify systemic interdependencies and seek to bolster the resilience of nodes of dependency. For example, substations upon which multiple Lifeline sector highly critical facilities depend could be prioritized for energy assurance enhancements. RIEMA's approach seeks to identify these interdependencies through its surveys. OER could consider requiring applicants for microgrid funding to complete these surveys (or a streamlined version), with information to remain accessible to EMA and the OER microgrid team.

An integrative approach could marshal all available "colors of money," including existing sources of potential project funding such as energy efficiency and DG support programs, C-PACE financing, ESPCs and PPAs where applicable, etc. Integrative perspective considers cost of ownership and not just first or capital cost, and takes into account non-traditional sources of costs and benefits for both the project and its relationship to the larger community of stakeholders and the environment.

As part of an integrative design approach, consider conducting a Request for Information (RFI) process to solicit input from marketplace stakeholders after a draft program design is put forward for comment, and before program design is finalized. RFI submittals should be posted on the program website. Public hearings for comment could accompany this process.

Take an all-hazards approach.

Reward solutions that address as many potential critical infrastructure disruption hazards as possible, and which can function independent of the EPS for as long as possible.

Seek alignment with existing objectives: emergency plans, GHG goals, energy programs, etc. Build on past accomplishments, current programs and efforts underway.

For example, numerous renewable energy DER, energy efficiency and LMI support programs exist. Rhode Island EMA has led a pioneering critical infrastructure protection effort including GIS mapping, including sector-specific resilience planning such as in healthcare. The Rhode Island Executive Climate Change Coordinating Council (RIEC[4]), SIRI and other projects are establishing relevant goals, tools and processes. RIIB's C-PACE program already includes microgrids as allowable measures.

Alignment is a two-way street. Utility system restoration planning, state planning for emergency response and recovery, climate change mitigation and adaptation, grid modernization, clean DG and other energy policies should consider and incorporate microgrids into those endeavors.

Prioritize public and community benefits, with a focus on support for local and state public agencies.

Public agencies own several types of critical facilities and missions (notably Lifeline sector facilities), and often have characteristics that can make complex energy project development particularly challenging, including:

- Constrained financial resources, particularly discretionary funds for short-notice project development (*e.g.*, for hiring consultants) and relatively long lead times for new appropriations
- Highly regulated procurement processes with relatively long lead times and stakeholder or voter approval requirements
- Numerous and diverse stakeholders with veto power, some subject to electoral cycles for tenure and turnover of key positions
- Lack of personnel with specialized skills or experience related to microgrid technologies
- Constrained ability to take advantage of some forms of funding support for DERs (*e.g.*, inability to use tax incentives or C-PACE)

Public agencies also have characteristics that can be beneficial for microgrid project development, including:

- Long term facility owner/occupant with attendant tolerance for longer-term investments
- Access to alternative financing opportunities (*e.g.*, bond issuance authority, Energy Savings Performance Contracts, virtual net metering, tax/business/energy improvement districts)
- Potential legal and rule-making authority

Microgrid program design that emphasizes support for public agencies (especially municipalities) could empower community public engagement and enhance democratic processes by enabling greater decision making ability, creativity and initiative at the local level.

A significant concern in community resilience planning is the risk that many small to medium enterprises might not survive prolonged outages (particularly those lasting longer than one week). The program could foster energy assurance for the economic resilience of local small firms and anchor businesses to help them stay in business, with the simultaneous benefits of their ability to provide the public goods and services during prolonged outages. C-PACE funding is a readily available option in this regard. Level 3 community microgrids can provide “downtown core” or broader scale energy assurance.

Prioritize protection of vulnerable populations: LMI, medically dependent, elderly, prisoners.

Provide support to historically under-resourced communities. Enable shelter in place options for vulnerable populations, where practical, with energy assurance for places of residence, public emergency shelters or “safe haven” zones. Community resilience and mass shelter in place capabilities are enhanced by clusters of community critical facilities that are Level 1 and Level 2 microgrids, as well as Level 3 community microgrids where deployable. It is worth noting that sometimes evacuation is the safest option—or only option—in certain emergency circumstances, even if shelter in place capabilities exist.

Deploy program funds cost-effectively by leveraging market forces, private investment and existing programs.

The program could “animate the marketplace”[230] by providing funds in a way that maximizes mobilization of third-party investment and marketplace innovation and creativity. Examples include:

- Minimize transaction costs with a user-friendly program and expedited administrative processes.
- Reduce project risks to improve the potential for third-party financing and help control costs.
- Fund feasibility studies that can spur marketplace activity even if the projects don’t receive OER program funding.
- Prioritize support for public-private partnerships.
- Provide funding in increments that “buy down” the cost of microgrid projects such that they can be financeable. For example, consider a hypothetical proposed $3 million CHP-based municipal microgrid design with a 27 year payback. In this case a $1 million capital contribution would reduce the payback period to 18 years, which would thereby enable the microgrid project to be procured via a 20-year term ESPC, PPA or ESA type contract with third-party private financing and life-cycle energy cost savings for the municipality. A $1 million program award could help mobilize $2 million in private investment, which could be a more economical use of public funds compared to the municipality and/or the microgrid program sharing the full capital cost of the project. The potential merits of this approach should be evaluated on a case by case basis.

[230] This phrase is borrowed from Richard Kauffman, Chairman of Energy and Finance for the State of New York.

- Use program (or possibly RIIB) funds for credit enhancement (*e.g.*, buying "points" to lower the interest rate for microgrid project loans).
- RIIB C-PACE funding relies on private capital to finance long-term investments in facility energy improvements with 10- to 25-year repayment periods. Microgrids are designated as "eligible measures" for C-PACE funding. It might be possible to use C-PACE funds at each of several properties that are connected in a microgrid configuration to help pay for shared energy systems.
- Exclude onsite generation from funding support, to encourage commercially-viable DG installations that are funded independently. Program funds could be used instead for electrical infrastructure such as switchgear and transformers, controls, wires, energy storage and other microgrid equipment.
- The program should help (indeed, require) applicants make full use of applicable DER and EE incentives and support. This has the added benefit of aligning the program with RI policy goals embodied in existing programs. For example, applicant projects could be required to undergo an ASHRAE Level 2 or 3 audit for energy efficiency opportunities, and to reduce load at least to the extent that each avoided "negawatt" or "negawatt-hour" is equal to or less than the cost of new onsite generation.

<u>Educate the marketplace with proactive outreach, template documentation and program transparency.</u>

Microgrids are a complex and novel topic and undertaking. Education could help make the program user-friendly, effective, economical, and successful, and could support effective mobilization of market forces. Program transparency in posting of program documents and templates, FAQs, funding applications, and operational data could support market learning.

<u>Make the program as user-friendly as possible, yet detailed enough to foster successful project design.</u>

Microgrid program and funding application design involve a balancing act between the benefits of making the program accessible and user-friendly, and the benefits of ensuring that participants think through vital aspects of microgrid project development. Onerous participation requirements could deter participation; yet both project and program success hinges in part upon attention to many details. In effect, to paraphrase Einstein, the task is "to make everything as simple as possible—but not simpler." Providing template documentation and feasibility analysis support reduces project risk.

<u>Enable microgrid host/owner an optimum degree of choice and foster market flexibility and creativity in microgrid development.</u>

All levels of microgrids feature highly case-specific purposes, applications and economics. Enable microgrid host sites to harness marketplace innovation and optimize their designs for their goals and circumstances. This should be an additional factor to making the program user-friendly, for example with modular and standardized features, as discussed above.

2.2. Policy objectives – The Biggest Decision: What (if any) changes to regulatory regime and role of EDC and/or third party market actors in MG development does OER want to pursue?

OER and other state stakeholders face important policy choices about the types of microgrids to foster; the potential changes to the roles of the EDC and other marketplace actors; and the extent of modification of the current regulatory regime with the EDCs. The biggest questions relate to potential reshaping of the EDC business model by allowing it to do things it does not or cannot currently do, and/or by allowing non-utility entities to do things that are currently exclusively EDC functions or to compete directly with EDCs for service provision. To what extent, if any, does the state wish to pursue changes to the regulatory regime and/or modify the regulated utility franchise? These issues relate to the ownership models and types of MGs that the state program is intended to support (*e.g.*, single-owner behind-the-meter microgrids, multi-user multi-facility microgrids, third party ownership, hybrid utility/private party ownership, utility-owned, etc.). They also relate to the vision and evolution of the nature and role of the EPS with regard to increased deployment of DERs and more "two-way transactive platform" business models or the grid, such as is envisioned in the NY REV process.

The authors recommend that significant modifications to the regulatory regime should not be undertaken for microgrid program development alone, in isolation from more comprehensive consideration. As noted above, state-supported microgrids are a means to an end— energy assurance for critical infrastructure mission assurance—and they can support multiple policy objectives simultaneously, but microgrids are not an end in themselves. Minor modifications that require regulatory approval, such as novel tariffs or other case-specific issues of rate design to support Level 1 or Level 2 microgrid development, probably do not constitute much of a challenge to the current regulatory regime. In contrast, policies intended to foster development of Level 3 multi-user community microgrids would involve more significant changes to the regulatory regime and the EDC business model that touch on nearly every aspect of energy policy and EPS planning and operations, of which microgrids are but one aspect. The most ambitious state microgrid effort, NY Prize, is occurring in the context of NY Reforming the Energy Vision (REV), a much broader, deeper comprehensive exploration of policies and business models relating to the future direction of the grid.

If Rhode Island wishes to revisit and re-imagine fundamental aspects of the EPS and the role of the EDC, the authors recommend that effort should be allowed the time and resources to develop a comprehensive, thoughtful, multi-stakeholder consultative process. A single-issue foray into tinkering with fundamental issues risks undesired unintended consequences. However important or time-sensitive is the need to improve energy assurance and socioeconomic resilience, those imperatives should not push microgrids into being the primary driver of fundamental change to the current regulatory regime.

Many Level 2 and Level 3 microgrids are built in phases; this approach can be applied to microgrid program design as well. An initial phase of strategy development and program definition with an integrative design approach can establish both short- and long-term objectives and measures. Successive iterations of program development can be undertaken with intervals enabling stakeholder feedback, analysis of lessons learned and implementation of program improvements. Each phase's structure and investments should provide a flexible basis for future development, with an eye towards technological developments and marketplace trends. A program comprising largely administrative measures can be initiated while longer-term, multi-stakeholder discussions and processes are pursued with regards to legislative and regulatory elements.

Below is a representative list of microgrid program design options listed in roughly ascending order of the degree and complexity of change required of the current regulatory environment:

- No change to minor change: An administrative or legislative program to foster single customer BTM Level 1 facility and Level 2 campus microgrids with grant funding. CT and MA programs and projects are generally in this category, with a few exceptions.
- Minor to modest change: An administrative or legislative program to foster small-scale multi-customer MGs on a limited and clearly defined basis. CT legislation enabling EIDs and creating special case exemptions and capabilities (*e.g.,* to distribute power across public ROW) for defined "municipal microgrids" (*e.g.*, as designated by local elected officials with DEEP approval) is generally in this category.
- Modest change: Enabling the EDC to own or contract for generation or modify the EPS under specific microgrid circumstances. NY Prize/REV is in this category.
- Modest to significant change: A legislative and regulatory program to enable the EDC to undertake actions currently constrained in order to create community-scale multi-customer microgrids. NY Prize/REV and to an extent MD and NJ are this category.
- Modest to significant change: Enabling the EDC to undertake novel cost recovery, *e.g.*, custom tariffs for local MG development. NY Prize/REV and to an extent MD and NJ are this category.
- Significant change: A legislative and regulatory program to enable the EDC and/or (particularly) third party entities to create community-scale multi-customer MGs involving novel forms of ownership and cost recovery would be a significant change. NY Prize/REV includes projects with utility involvement. MD is considering enabling third party competition with regulated utilities in a microgrid formation marketplace. NJ DPU is also considering similar options.

In particular, multi-user "community" or "Level 3" microgrids would be difficult to develop under current (actual or perceived) regulatory and legal constraints. Factors include:

- EDCs can own only a limited amount of generation (15 MW total statewide). It is not clear if the EDC can own energy storage.
- In general, due to the regulated "obligation to serve" all customers, utilities and EDCs are hesitant to consider rate-basing any particular microgrid's project costs across their customer base. On equitable principle, EDCs wish to avoid requiring customers who do not directly benefit from a microgrid to share its costs with those who do. Currently the EDC has some ability to develop custom tariffs for enhanced service reliability for certain customers, primarily through provision of a secondary service feeder (essentially

an "N+1" reliability-via-redundancy strategy). It is not clear whether this capability can be used to enable the development of case-specific custom tariffs designed to recover microgrid development costs from the customer(s) that most directly benefit from those investments.[231]

- It is not clear that EDCs are currently able to enter into hybrid ownership arrangements for microgrids, or what constraints might exist on that capability.[232]
- Third party development of multi-user level 3 community microgrids is barred or greatly inhibited by the (actual and perceived) risks triggering challenges to the regulated utility monopoly franchise. In general, third parties are not allowed to sell power to other parties, or to distribute power across a public right of way or utility easement without permission.
- National Grid representatives have noted that in most Rhode Island localities, relatively significant modifications or upgrades would be required to adapt local segments of the distribution system to enable community-scale microgrid formation. Potential modifications could include sensors, communications, controls, switches, sectionalizers, relays and the like to enable safe operation of a local-scale islandable segment of the EPS with integral DERs. Some of these "smart grid" type upgrades may be in place in certain areas but are not widespread. OER or the PUC could consider modifications necessary to enable utility-directed or hybrid-ownership Level 3 community microgrid formation.

OER could consider convening a working group with representatives from the PUC, EDC and other stakeholders to assess what microgrid-related actions by the EDC, customers, and/or third party non-utility microgrid developers are allowable and desirable under the current legal and regulatory regime. Such a detailed assessment is beyond the scope of this report. This working group could then consider what changes (if any) to the current regulatory environment would be desired to foster development of multi-user Level 3 community microgrids.

Docket 4600[233] involves related developments in DER and EPS investment evaluation employing a Cost/Benefit Framework that includes costs and benefits to the EPS that are not often monetized, including societal and environmental considerations.

2.3. Administrative – Program design

The following recommendations are considered to be administrative program measures and actions that OER could undertake under current conditions.

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[231] For one example of this approach, see National Grid's proposed project in Potsdam, NY in these context of REV and NY Prize.
[232] *Ibid*. For one example of this approach, see National Grid's proposed project in Potsdam, NY in these context of REV and NY Prize.
[233] www.ripuc.org/eventsactions/docket/4600page.html

Provide program funding to assist with MG development at program & project level

Funding is required to administer a program, with or without contacted consulting support. Program funding can be applied through options including:

- Grants
- Credit enhancement (*e.g.*, interest rate buy-down)
- Production-based support (*e.g.*, on a $/kWh basis over a designated term)
- Low-interest loans (potentially linked to a revolving loan fund).

Funding sources: These can influence program deployment depending on the associated conditions and requirements. Large block grants such as HUD CDBG-DR funds or foundation support can come with stipulations about what type of projects get funded. SBC, RGGI, ACP or other program funds carry their own requirements, which might be more flexibly applied. State bond funding can be subject to AHJ approval and budgetary pressures. Ratepayer funding is subject to PUC oversight. The program should integrate and leverage existing programs, incentives, feed-in tariffs, and other funding support for DERs to the fullest extent.

Program administrative costs: These include the FTE staffing effort to run the program, which will surge during program milestones such as launch and application review. Program staff should be knowledgeable about microgrid technologies and programs, and could benefit from contracted specialist support. OER could consider more narrowly-focused technical support, or contracted full scope program administration.

Project funding support: Funding assistance to would-be microgrid developers is vital because only a minority of potential critical facility microgrid retrofit projects will be economically viable without outside contributions. For greatest leverage, program funding should be as comprehensive and flexible as possible to cover installed costs including "soft costs" of feasibility assessment, design, engineering, permitting, siting, commissioning, etc. as well as the capital cost of the equipment. Program outreach should include comprehensive information on all of the complementary sources of potential funding, from municipal bonds and Tax Exempt Lease Financing to PPAs, ESAs, utility and state incentives, rebates and feed-in tariffs.

Program funding will be limited, so funding-eligible aspects of microgrid development are listed below in suggested order of priority, most important first:

- *Eligible equipment - Electrical infrastructure* not *including generation or storage* (*e.g.*, point of common coupling, wires, controls, switchgear, transformers, communications, protective relays and transfer trips, etc.): This is important because these aspects of microgrid infrastructure do not directly produce energy cost savings, although they can contribute to strategies that do so. CT took this funding approach in the first two iterations of program development.
- *Feasibility analysis*. Programmatic funding for feasibility analysis support could significantly increase program participation on schedule, reduce project risk, and

potentially spur market activity to develop projects that ultimately do not receive program implementation support. Providing up-front planning funding will enable more public sector entities to participate, with greater effect than would cost reimbursement.
- *Eligible equipment - Energy storage systems*. Energy storage systems (ESS)—primarily batteries but also thermal energy storage (TES)—are not necessary for all microgrid designs, but play a vital role by firming up intermittent renewable energy generation such as solar and wind power, and can enable other forms of cost reduction and revenue generation. ES is listed before generation as a funding priority primarily because in most cases battery ES cannot yet pay for itself in a reasonable timeframe. ESS such as lithium ion batteries are maturing rapidly and prices are dropping, yet costs have not yet come down far enough to enable commercially-viable economical applications in more than a minority of circumstances in the Northeast, without programmatic funding support. CT now considers ES eligible for funding support, as do CA, MA, NY and NJ.
- *Eligible equipment - Generation and energy storage equipment*. Generation can often pay for itself (depending on the customer's ROI or payback requirements), and numerous clean energy support programs exist. But many projects and would-be owners still require financial assistance, particularly in the public sector. CT now considers generation eligible for funding support, as do MA, NY and NJ.

Capital Contribution and Credit Enhancement strategies could complement the Eligible Equipment approach, and could foster applicant use of private investment. See section C2.3 for further discussion.

In other state programs, per-project awards have ranged from a few to several hundred thousand dollars, and in cases in the low millions of dollars.

Develop multi-stakeholder inter-organizational program administration team

Program design should be undertaken with a multi-stakeholder team including, but not limited to, those organizations directly involved in program administration. These organizations could include:

- OER (*e.g.*, legal, distributed generation, energy efficiency and LMI program representatives)
- EMA and related emergency planning organizations (*e.g.*, Critical Infrastructure Protection and RIGIS liaison representatives)
- RIIB (*e.g.*, C-PACE program representatives)
- PUC/DPUC (including rulemaking and ratepayer/LMI advocacy program representatives)
- National Grid (both electricity and natural gas system personnel and in particular representatives from interconnection, system restoration, distributed generation, customer energy use data access, and energy efficiency functions).

Critical facility owner/operator and microgrid developer stakeholders could be considered the primary "target market" of the microgrid program, and could provide input to program design via an RFI process, a public comment period, and/or other forms of engagement and solicitation at key points in program development, but don't necessarily need to be regular participants in program design. Examples include:

- EMA and related public safety organizations (*e.g.*, Critical Infrastructure Protection and RIGIS liaison representatives; state police and corrections; municipal police, fire and EMS chiefs; National Guard; public health, Red Cross and other emergency shelter operators)
- DOA (*e.g.*, state facilities management representatives)
- Rhode Island League of Cities and Towns, Rhode Island City and Town Manager's Association, The Rhode Island Association of Fire Chiefs, Rhode Island Police Chief's Association, Rhode Island Association of Emergency Managers, Rhode Island Public Works Association and similar associations of elected officials, town managers, facility managers, public safety and emergency managers, as well as procurement, financial and legal representatives.
- Critical facility sectoral stakeholders, particularly those involved in prior energy assurance planning with EMA and OER (*e.g.*, the Department of Housing and the Hospital Association of Rhode Island), and Chambers of Commerce to promote local economic resilience through small business energy assurance.
- Critical infrastructure and critical facility owners' associations (*e.g.*, fuel suppliers, public and private sector facilities managers, K–12 and higher education facility managers)
- Microgrid equipment, services and developer firms (*e.g.*, renewable energy and distributed energy resource developer associations, controls manufacturers, Energy Services Companies). OER should consider developing a list of pre-approved contractors, categorized by microgrid-related service offering.

Program implementation should involve representatives from the core stakeholder group, including at a minimum OER, National Grid, and RIIB (as well as program administration contractors, if any).

<u>Provide EDC with direct role in program and in MG project planning and development, and require microgrids to coordinate with the EDC on design and operations</u>

The EDC has a unique role in microgrid program implementation. It operates the energy distribution networks and is the primary source of information on systems infrastructure, costs and benefits; seeks PUC approval for cost recovery for system investments and tariff design; approves DER interconnections; implements incentive programs; and provides billing and historical usage data. A microgrid program will require many parts of the EDC the engage with customer development of Level 1 and Level 2 microgrid projects; the EDC is intrinsic to level 3 microgrid development.

OER will need to work closely with the EDC on program development and implementation. OER could consider requiring microgrid project developers to work with the EDC by making an interconnection application a prerequisite for funding applications (as CT does), or including the EDC in feasibility assessments (especially for Level 3 microgrids, as NY Prize does). A microgrid program could impose a significant burden on EDC staff time, for example by a spurring a surge in energy usage data and interconnection information requests.

Preplanning, streamlining and standardizing anticipated microgrid-related processes could reduce costs and uncertainty for both developers and the EDC. OER could develop plans or processes for EDCs to:

- Provide EPS infrastructure information to microgrid developers (*e.g.*, a pre-interconnection application consultation during feasibility analysis). This requires careful planning as critical infrastructure protection-related information is considered sensitive and typically restricted for public access.
- Identify locations (to OER, if not to developers) where MGs would provide the greatest value to the distribution system.
- Standardized pre-approved interconnection-ready template designs for modular microgrid technologies, configurations and protective measures (*e.g.*, switching for single-generator microgrids with inverter-controlled CHP, or REG-funded PV-plus-storage installations).
- Develop rate locks or other strategies to reduce tariff risk facing microgrid developers over planning for longer financing terms; this is partly a regulatory measure.

Key microgrid project and program considerations about respective roles and responsibilities to be clarified with the EDC include:

- Who owns microgrid distribution infrastructure, the customer/developer or the EDC? CT specifies that the EDC owns and operates the distribution infrastructure within municipal microgrids, although this has been less definitive in practice. The NJBPU report recommended that microgrid developers pay for, but then turn over to the EDC, those portions of microgrid electricity distribution infrastructure that cross public ROW and/or utility easements.[234] This approach has the potential benefit of providing a solution to the hurdles facing non-utility entities that wish to distribute power across a ROW without challenging the utility franchise.
- Who controls a microgrid, *e.g.*, with regard to deciding to disconnect from the EPS? What are the circumstances that will cause the switch(es) connecting the microgrid to the utility to be open or closed? How do the microgrid owner/developer and the EDC communicate about these decisions? It is important to the EDC (and potentially to the ISO) that there be advance notice of a microgrid removing or adding its load to the grid.
- What are the operating rules for privately owned microgrids? Any microgrid's relationship to the EDC to facilitate safe management of grid operations is essential.

[234] NJBPU, *Microgrid Report*, 2016, p.79.

There does not have to be, and probably should not be, a single answer for this set of questions; but there should be a process for answering them that does not act as a barrier to microgrid development.

Microgrid projects need to coordinate with the EDC for safe management of grid operations, and must be designed to meet interconnection requirements. Recommendations include:

- Require that projects which apply for funding must first submit an interconnection application to the EDC.
- A defined microgrid must sign a Letter Of Agreement (LOA) with the EDC that defines operating rules, roles and responsibilities, and establishes coordination and coordination protocols around islanding which are not addressed in the interconnection. A template LOA could define a set of allowable options for Point of Common Coupling configurations, technology types, and operating roles. A microgrid could be required to notify the EDC in advance of its intention to either disconnect from or reconnect to the grid, within a reasonable time period TBD (*e.g.*, 5–10 minutes, or 1 hour) sufficient to enable the EDC (and possibly the ISO) to prepare for the resulting change in load at that location on the distribution network. The EDC could be allowed to request, or require, that a microgrid disconnect from the system (a microgrid should be compensated for this demand response function).

<u>Define microgrid and critical facility for program participation and project eligibility to utilize program-related enabling rules and exceptions</u>

The program should define microgrids for program purposes. The DOE definition can serve; others are more concise.

One benefit of a programmatic definition is that clearly-defined microgrid project conditions could create a unique space in which special conditions, new rules or exemptions, and experimental administrative/legislative/regulatory measures can apply. This definitional "safe space" could be restricted to those projects that receive program support, or extend to all projects that meet the definition. This approach could reduce programmatic risk by limiting unintended consequences from program-specific measures, and reduce political risk by fostering stakeholder buy-in.

CT took this approach by defining municipal microgrids as meeting certain conditions (*e.g.*, projects approved by local elected officials with 2+ critical facilities as defined in a broad list), and enabling specific rules and measures applicable only to that category of customer (*e.g.*, VNM for up to 10 facilities, ability to distribute power across a public ROW).

Recommended program aspects applicable to defined microgrids include:

- Require blessing of local elected officials / government for program eligibility [CT, MA, NY]
- Preference for assistance to help develop Level 2 campus or Level 3 multi-meter, multi-building projects. [CT, MA, NY]
- Allow Level 1 single facility BTM microgrid projects [MA]

The vast majority of potential retrofit microgrid projects will be Level 1 single-facility BTM-type opportunities, if the program makes them eligible applicants for support (CT did not; MA did). OER can expect relatively smaller numbers of applications for Level 2 campus or Level 3 multi-meter, multi-building microgrid types, due to factors including:

- It is relatively unusual for groups of critical facilities to have characteristics and configurations conducive for economical microgrid development, *e.g.*,
    - Proximity
    - Complementary energy use patterns
    - Facility mechanical/electrical/structural systems readily modifiable to host and be supported by DERs
- Cost and complexity challenges that require significant owner/developer resources
- Common legal and procurement barriers to development of Level 3 multi-user, multi-facility microgrid development under the current regulatory environment, and a lack of precedent examples and business models that successfully address these barriers

If program resources are limited, OER could consider providing program support preferentially or exclusively to Level 2 and Level 3 microgrids due to their complexity and resource-intensity, relative to Level 1 microgrid projects. For example, the program could provide more feasibility study support to Level 2 and Level 3 applicants.

OER could consider defining the range of microgrid types and business models the program will support. For example, the program could include or fund only public sector microgrids, or enable partly- or solely-private sector projects. Due to the relative limitations on program funding and the common capital constraints in public and nonprofit sectors, solely private sector projects should be encouraged to apply their own financial resources and leverage programs such as C-PACE. These customers could be considered eligible for program enabling rules and legislation, for example with the approval of local elected officials.

Related issues that would be useful to define or clarify in program eligibility include:

- Can special rules and exceptions for microgrids be utilized by projects that don't receive program funding, but meet the program definitions and requirements? (For example, the ability to distribute power across a public right of way in a municipally-endorsed microgrid). The authors recommend that this be allowed, perhaps in return for microgrid performance data reporting.

- What ownership models for microgrids are allowable? Recommendation: Provide broad latitude for customers to select their own procurement strategy or business model, as long as their microgrid meets program requirements.
- What are the operating rules for privately owned microgrids? Any microgrid's relationship to the EDC to facilitate safe management of grid operations is essential. Recommendation: A defined microgrid must sign a Letter Of Agreement (LOA) with the EDC that could address operating issues. A microgrid could be required to notify the EDC in advance of its intention to either disconnect from or reconnect to the grid, within a reasonable time period TBD (*e.g.*, 5–10 minutes) sufficient to enable the EDC to prepare for the resulting change in load at the location on the distribution network. A template LOA could define a set of allowable options. An LOA could address issues such as the following:
    - What are the allowable Point of Common Coupling configurations, technology types and rules?
    - Who controls the "disconnect switch" to island the microgrid, and what are the circumstances that will cause the switch(es) connecting the microgrid to the utility to be open or closed.

There does not have to be and probably should not be a single answer for this set of questions, but there should be a process for answering them that does not act as a barrier to the whole idea.

<u>Develop and deploy a robust education program</u>

For most RI energy marketplace participants and facility owners, microgrid design and operational configurations are relatively new concepts and involve unfamiliar combinations of both existing and newer technologies and business models. A microgrid support program itself will be new to all involved, and can be thought of as being somewhat "ahead of the marketplace" despite growing experience in nearby states and the regional vendor industries. It will be very important to raise stakeholder awareness and make often-complex technical and financial information accessible to a wide range of stakeholders. Recommendations to help strike a balance between accessibility and complexity in microgrid program design are discussed further below.

The program should include a robust educational component. Recommended elements include a program website that could host program documents and post answers to Frequently Asked Questions (FAQs). E-mail notifications could be sent to an aggregated recipient list of contacts from prior programs as well as new registrants. Public meetings that are comprehensively advertised to key constituencies and target audiences could provide a forum for presentations by the integrated program team with representatives from OER, RIIB, National Grid (and others as appropriate) explaining their respective roles and subject matter. This approach could also demonstrate to the marketplace that the key public and private sector stakeholders on the microgrid program team share unified and collaborative support for program goals and processes.

Educational events could be combined or complemented by “meet and greet” events that introduce potential microgrid hosts/owners to vendors, which could staff booths and make brief presentations (*e.g.*, 2 minutes each) about their goods and services. It is important to maximize the benefit of “meet and greets” by ensuring robust participation by municipalities and other critical facility owners (requiring effective program outreach and possibly RSVPs) to avoid having audiences that are too vendor-heavy and result in little market impact relative to the collective time and effort.

<u>Use project planning guides, and a detailed RFP / application that defines technical and economic requirements [CT, MA]</u>

Project planning guides and reference material: The program could create or reference existing planning guides with information on common microgrid applications, technologies, configurations, critical load assessment, procurement strategies, permitting/siting requirements, funding application guidelines, etc. MA funded a legal assessment of issues pertaining to actual or perceived barriers to distribution of power across public ROW and utility easements by non-utility entities, to inform policy and project development. Resources could be posted or linked on the program website. This report’s annotated bibliography provides some examples and topical guidance (*e.g.*, NYSolar Smart DG Hub fact sheets, IDEA CHP planning guide).

RFP-type funding application forms: The RFP could require detailed information about key subjects that both support comparative evaluation of applications, and address vital aspects of microgrid project development that applicants should consider. A comprehensive RFP could pose many challenges for novice applicants, but also could serve as an educational tool that prompts applicants to consider vital aspects of microgrid project development. For example, the RFP could request information about subjects including:

- Public purpose, critical mission, and population to be served by critical facilities in proposed microgrid
- Relationship of generation capacity to load (*e.g.*, reserve or excess capacity, ability to follow dynamic loads or shed load)
- Black start capability
- Duration of operation based on secure fuel supplies
- One line diagrams displaying protective relays, controls, communications and other features
- Voltage drop calculations
- Interconnection (pre-)applications
- Ability to withstand specified hazards (*e.g.*, Category I hurricane winds, inundation, cybersecurity)
- Project business procurement model and financial performance (*e.g.*, project cost per kW and kWh, sources of revenue, applicable incentives and other supplemental funds, annual operating and maintenance costs, ROI/simple payback period)

The Connecticut DEEP program RFP is a good example of a comprehensive application. Standardization of the format and metrics of project financial information requests supports funding applications evaluation by the microgrid program team. MA CEC is developing standard business model template spreadsheets for municipalities to use for project planning.

RFPs that request a large amount of detailed information impose program trade-offs. Upsides include fostering higher quality microgrid designs and funding requests, with attendant improvements in the probability of successful development of those projects that receive funding support. Downsides include setting a high bar and a steep learning curve for would-be microgrid hosts and developers, which can impose significant and possibly prohibitive up-front costs on applicants (especially municipalities and other public agencies). The more detailed the RFP, the more beneficial is programmatic support for feasibility analysis.

Business model templates: Consider providing business model spreadsheet templates for applicants to fill in for basic microgrid types, particularly if the program includes recommended or pre-approved business models. This could require a significant program effort, and could be a feature of a more robustly funded program. A similar approach was undertaken by the MA CEC, and to a certain degree by NY Prize in the cost benefit analysis spreadsheets provided as templates for feasibility studies, which included societal benefits.

<u>Consider a two-tier process to provide high-level screen of feasibility analysis [CT, NY]</u>

The primary objective of this recommendation is to benefit potential microgrid developers and critical facility owners by enabling them to develop a pre-screening process involving high-level estimates and a minimum of effort, so that OER can let projects know whether they "made the cut" to proceed to a higher level of feasibility analysis. This goal could be supported with a Phase I pre-screening application, based on readily available information and less likely to require consultant support for facility owners to complete (although some applicants might require consulting support regardless, if the program does not fund or provide it). A two-step process could help educate the marketplace and screen out projects unlikely to be successful or economical, without asking applicant municipalities to spend a lot up front for an uncertain return. It would require greater total effort by the OER program team but would reduce the total burden on applicants. CT chose a two-step process in its first round of funding, but subsequently condensed the application process into one more detailed application.

This project phase could include a streamlined points-based scoring process with abstracted values for specified hard-to-monetize criteria. If OER provides robust up-front feasibility analysis support, this separate step might not be necessary.

<u>Provide funding support for feasibility analysis</u>

The downsides of RFP complexity and detailed information requirements could be mitigated with programmatic support for feasibility analysis. Such funding increases program size and cost but is highly likely to provide better results, including:

- Significantly increase program participation
- Enable prompt planning in response to program launch
- Improve applications' quality and timeliness to meet program deadlines
- Reduce project risk
- Consistently employ programmatic CBA metrics, such as those used in pilot project or TBD
- Potentially spur market activity to develop projects that ultimately do not receive program implementation support.

Support could consist of up-front grants and/or technical support, or reimbursements; and pre-mapping of potential microgrid locations (*e.g.*, clusters of proximal critical facilities).

Feasibility analysis funding and technical support: Providing up-front planning funding will enable more public sector entities to undertake microgrid planning in a timely fashion (or at all), with greater effect than would feasibility study cost reimbursement. Up front assistance is particularly helpful if the amount of time between RFP issuance and the application deadline is relatively brief, and if the level of detail required for funding applications and cost-benefit analysis is high. The marketplace can provide the necessary technical assistance, but if program funds are available, OER-contracted consultant teams can provide highly user-friendly support to public entities, with the attendant benefit that assessments are conducted on an equivalent basis with common metrics and methodologies. Reimbursements are better than no funding at all, but generally are of limited value to municipalities that lack discretionary funds to engage consulting support to develop feasibility studies and funding applications.

Other states have provided $50,000–$60,000 in reimbursements or grants for initial feasibility assessments at the project level (CT, MA), and up to $100,000 at the community level (NY Prize). MA DOER provided both grants and contracted technical support teams to assist municipal feasibility analysis. CT reimbursed up to $50,000 per project, but only those that were ultimately funded.

Potentially applicable funding is currently available. RI's REF program includes loans for feasibility analysis that could be used to support microgrid development involving applicable generation. RIIB can provide municipal planning assistance funding.

Mapping information conducive to microgrid development: The RIGIS system provides a great deal of geographic information to inform microgrid project planning, from critical facility locations and demographic factors to flood zones. This information can be very useful for planning all types of microgrids. OER can consider developing additional mapping of critical facility geographic clusters or energy use, but such efforts must be carefully targeted to provide a significant return on the investment.

Boston Redevelopment Authority (BRA) conducted a study of estimated thermal energy use by clusters of buildings city-wide in Boston, MA, and NJ mapped clusters of critical facilities; both studies were made public to help inform project development. However, such innovative approaches are of limited utility without an accompanying business model that is able to address barriers to development of Level 3 multi-user community microgrids. The authors recommend that the state should only fund these types of assessments if it intends to make the legislative and regulatory changes needed to enable business models for the development of Level 3 microgrids; for further discussion, see section 2.2.

<u>Prioritize energy efficiency and clean energy</u>

Efficiency: RI has a strong record and policy support for energy efficiency, earning a #3 ranking among all 50 states from the ACEEE State Scorecard. The Resilient Rhode Island Act calls for the development of strategies and implementation measures to achieve the following greenhouse gas emissions reduction targets: 10% below 1990 levels by 2020, 45% below 1990 levels by 2035, and 80% below 1990 levels by 2050. Governor Raimondo's "Lead by Example" Executive Order 15-17 states: "State agencies shall achieve, subject to funding opportunities and constraints, an overall collective reduction in energy consumption of at least 10 percent below fiscal year 2014 levels by the end of fiscal year 2019."

Energy efficiency is sometimes referred to as the "first fuel," as saving energy is typically less expensive than supplying it. In a microgrid planning context, typically load reduction is cheaper than onsite generation on both a kW- and kWh-basis; a "negawatt-hour" of conserved or avoided energy use has no emissions; and energy supply that isn't needed can't be interrupted. Yet "cheaper" is good but can be considered a short-term benefit. Efficiency's greatest value is derived from targeted applications that yield longer-term benefits to the state and the EPS, for example by displacing unnecessary investments in "business as usual" fossil fuel generation or T&D capacity sized for rare and otherwise avoidable demand peaks. Docket 4600 seeks to develop evaluation methods to help identify opportunities for realization of the greatest value, with consideration of sources of value that are not traditionally monetized.

It would not be fiscally prudent to expend program funds supporting investments in generation that powers inefficient buildings, which wastes energy. CT and MA requires that applicant projects undertake a detailed energy audit. OER could require that applicant projects:

- Conduct an ASHRAE level II or III energy audit on all microgrid-served facilities, to identify economic efficiency improvements for critical loads to be served in island mode, assessed at the project level as a comprehensive portfolio of energy conservation measures (ECMs) with a portfolio-level ROI or payback period that optimizes load reduction. [CT]
- Investment in load reduction first, at least up to cost parity with proposed DG on a kW and kWh basis. [CT]
- Use existing energy efficiency incentive programs to minimize required DG capacity. [CT, MD]

Program designers should note that load reduction can contribute to unintended negative impacts on generation planning in Level 1 microgrids in particular. By reducing onsite DG capacity requirements (notably in the sub-megawatt range), there can be a trade-off that making the "prime mover" energy generation system smaller might have two related effects on procurement options:

- A poorer ROI and longer payback period because a relatively smaller system produces fewer units of lower-cost energy, which generate less annual cost savings and positive cash flow to offset the installed cost or repay the financing over time. This can be challenging for smaller-scale CHP installations where the relative cost share of the balance of system "appurtenances" (*e.g.*, heat exchangers, pumps and pipes, dump radiators, absorption chillers, etc.) is not that much less for a 400 kW system than for a 1 MW+ system, but the lesser annual savings of a smaller system take longer to pay off the appurtenances than would a system that is twice or three times the size or larger.
- This effect also hinders the viability and availability of third party financing and ownership options such as PPAs or ESAs.

Despite these factors, manufacturers such as Aegis and Tecogen offer modular, packaged CHP systems in the 30–100 kW range that in cases come with integral inverter chips or similar controls and black start capability to enable islanded operation, and can be provided under PPA or ESA type financing.

Clean(er) energy: Renewable and clean(er) energy sources such as PV, wind and CHP are preferred generation options for microgrid program development in other states and could be for RI as well, for reasons including:

- Alignment with broader policy goals, including:
  - Renewable Energy Standard (RES): Goal of 11.5% renewable energy for 2017; this requirement is set to increase by additional 1.5% each year until the goal of 38.5% is reached by 2035
  - Governor's E.O. 15-17: Goal of 100% renewable energy for state facilities by 2025
  - The Resilient Rhode Island Act: Sets targets for reducing greenhouse emissions to 45% below 1990 levels by 2035 and to 80% below 1990 levels by 2050
  - Governor's "1,000 by '20" goal of 1,000 MW of clean energy by 2020, a 1000% increase from the 2016 baseline total of ~100 MW of existing capacity
- Existing funding support from programs, incentives, tax credits
- Constant-duty assets provide benefits during typical "blue sky" daily operations
- Low-cost (CHP) or no-cost (PV, wind) fuel supply
- Fuel supply can be difficult to interrupt (less so with CHP)
- Climate risk mitigation and adaptation via the same investments
- Siting and permitting can be easier (especially PV, less so wind)

There are potential trade-offs and downsides as well, including:

- Intermittency (PV, wind)
- Relatively low energy density (PV, wind)
- Most inverter-based systems are not configured for island mode operation during outages (PV, wind, some CHP)
- Hazard exposure to disruptions of natural gas supply (CHP)
- Retrofit challenges of facility compatibility for onsite DER modifications to serve critical loads

Many of these trade-offs have solutions, some of which are cost-effective already or will be soon (*e.g.*, energy storage systems). Other factors pose bigger challenges in the context of smaller microgrid deployments than they pose to the EPS (*e.g.*, intermittency or energy density). Innovation is constantly expanding solutions and opportunities.

The RI microgrid program could include the following features:

- Prefer or require cleaner DG deployments in areas where they will provide the greatest benefit to the EPS and the community, as indicated by the valuation methods in LCP, Docket 4600 and potentially new valuation methods that the OER program could create.
- Prefer or require microgrid projects to deploy cleaner generation, for example to help attain policy goals.
- Prefer or require microgrid projects to utilize clean generation procurement support from other programs, as well as new forms of DER support that the OER program could create.
- Require that new DERs and load reduction reduce the microgrid facilities' annual "carbon footprint" or greenhouse gas (GHG) emissions from Scope 1 (*i.e.*, from onsite sources) and Scope 2 (*i.e.*, from purchased energy generated offsite) sources, relative to pre-project emissions under typical "blue sky" operating conditions.
- Prefer or pre-approve modular sets of CHP / inverter / controls for island mode operation (although "one size fits all" packages might not be possible).
- Prefer or pre-approve modular sets of energy storage / inverter / controls to retrofit existing PV (especially installations procured via PPA) to make them islandable (although "one size fits all" packages might not be possible).
- Develop voluntary standard "islandable PPA" template with PV developers.
- Create a variation on REG feed-in tariff to support island mode operations (*e.g.*, higher rates and/or longer term to support the additional balance of system costs to enable grid-independent operations). This capability could be a requirement for future REG or other DG support programs.

Role of existing and new fossil-fueled generators: The program could define its relationship to the role of fossil fuel back up generation (BUG) in funded projects and/or designated microgrids. Although diesel or natural gas BUGs are standby assets rather than constant-duty options, and they not renewable or particularly clean, they are in wide use as the primary option for emergency or backup power. Some types of critical facilities are required to maintain BUGs with 72 hours of diesel fuel storage, and microgrid retrofits will not supersede this requirement. BUGs are proven technologies and can have superior load-following characteristics. But their fuel supply is subject to disruption, they have high emissions and constrained run-hours in non-emergency conditions, and both poor maintenance and testing procedures can contribute to lower than desired availability factors. As many critical facilities already have a fossil fueled BUG, the program could define the options for integration into microgrid configurations.

Microgrid designers will need to determine the relationship that retrofit, new clean DERs would have to existing BUGs. For example, will cleaner DG serve the same critical load circuit as the BUG? If so, will cleaner DERs operate in tandem with the BUG, or will cleaner DG be dispatched first to serve critical loads alone while the BUG provides standby backup power in case the clean DG can no longer do the job? These decisions are case-specific and the program should determine what if any constraints to put on microgrid designers.

Although the authors do not recommend that the program provide funding for BUGs, program eligibility criteria could include:

- Allow BUG to provide bridging power to serve critical loads during open transition to island mode, until cleaner DG comes (back) online to serve critical loads.
- Prefer or require BUG to serve critical loads when cleaner generation cannot.
- Allow BUG to provide black start to cleaner DG (*i.e.*, to provide power needed to re-start cleaner DG systems if they shut down in grid-independent mode).
- Allow BUG to contribute to serving critical loads in island mode, with appropriate controls and sequence of operation.
- Allow specified configurations. For example, if a facility has both a PV+ES installation and a BUG, the PV+ES system can be configured to serve the critical loads until depleted, then switch to the BUG serving the loads (simplest); and/or the BUG can charge the ES (a bit more complex); or the PV can operate in tandem with the BUG (complex).
- If all-BUG configurations are allowable, require only multi-meter combinations of 2+ buildings where microgrid formation saves fuel and improves energy assurance.

A basic question is whether the program will fund BUGs. The authors recommend that the program avoid funding entirely BUG-based Level 1 single-facility microgrids, or it will risk expending all its resources on this configuration with no clean energy benefits. In some cases, critical facilities will lack sufficient natural gas supply and/or will require higher energy density and longer duration of operation than retrofit intermittent renewables can provide. In these locations, the program could consider support for connecting multiple existing (or new) diesel BUGs to form Level 2 microgrids. Sometimes a critical facility will have a large BUG capable of more fuel-efficiently serving the combined loads of nearby critical facilities that might or might not possess their own BUGs, compared to each facility running its own BUG during an outage. If the program funds projects with new BUGs, it could consider the following options:

- Prefer natural gas BUGs, where applicable.
- Prefer or require that the BUGs to be duel-fuel to lessen their dependency on one fuel supply chain.
- Require that new diesel meet or exceed Tier 4 air emissions standards [CT].

Employ rolling application deadlines and/or allow several months for feasibility analysis and application development, especially for municipalities [CT]

The program could provide sufficiently long RFP development periods or rolling deadlines to facilitate participation by public sector organizations with often-prolonged processes for decision making, procurement and energy/facility capital improvement project development. The tighter the deadlines, the more challenging the application process. The timing of RFP release and response submittal deadlines should consider typical municipal budgeting cycles. Six month timeframes proved challenging for many applicants in CT and MA, even where feasibility assessment support was provided up front. Nine to twelve month intervals might allow more time for successful funding application development, but could carry some risk of a loss of project applicant team focus relative to the inducement of a more aggressive schedule. Rolling deadlines can help address these issues, perhaps with a backstop period of 12–24 months.

Program planning and scheduling should also consider the time it will take to review and make awards, and notably to finalize funding contracts between the state and recipient municipalities, and add those intervals to the project development timeline. Program timing should also consider alignment where possible with related DER support programmatic deadlines, such as the timing of REG program open access periods.

Employ design and construction schedules with ample time and administrative flexibility

It is important to provide sufficient time and flexibility with awardee project development schedules to allow for protracted municipal procurement processes, marketplace learning, and common design and construction schedule slippage. Microgrid project novelty and complexity are drivers of project delay. In both CT and MA only a minority of funding recipients remain on schedule and most are not yet operating as of early 2017, even many months after funding awards. Numerous projects underwent fundamental design revisions, or encountered problems with their initial concept that were not revealed or anticipated by feasibility analysis or funding application review. The microgrid program team should be as flexible and reasonable as possible; should expect delays; and should be willing to grant extensions of six months of more.

There could be trade-offs between allowing sufficient time for project development to enhance success, and the generic consideration that a program spending public dollars could experience political pressure to demonstrate results within a reasonable reference timeframe, including factors such as the financial half-life of the source funding and the tenure of officials subject to the outcomes of electoral cycles.

Application review, selection process & criteria

A fundamental aspect of the proposed microgrid program could be the release of an RFP to issue a competitive solicitation of applicant projects, as the other state programs have done. Generally, an RFP comprises technical requirements, selection criteria, and a scoring/point system. The RFP could establish criteria for selection including prerequisites such as minimum performance requirements, and request information about project technical and financial characteristics. OER and its program team would evaluate the RFP responses or funding applications and decide which to fund, and how much. This would involve a scoring process to inform selection. There are two primary strategies:

- Specify a rigorous set of technical requirements and evaluate on a shorter list of selection criteria (*e.g.*, MA)
- Specify only a few requirements, provide a longer list of criteria, and set up a more involved scoring process (*e.g.*, CA)

The structure of the criteria depends on the structure of the program. Some states self-perform preliminary technical analysis/design, such as MA with contracted feasibility analysis teams; some require that analysis as part of an application (NY); some provide funding for this purpose (MA, NY), some reimburse if successful (CT).

See below for a list of each state's selection criteria. See also a list of Arup recommended selection criteria and measurement indicators. Common minimal technical requirements in other states' programs include:

- Minimum number of critical facilities
- Minimum number of hours critical loads are served during normal operations
- Ability to island for ___ duration
- Black start capability
- Adherence to codes, regulations, interconnection standards
- Ability to maintain power quality within specified limits
- Load shedding capability
- Can/cannot cross public ROW
- Most programs listed out specific eligible technologies

Scoring methodologies can inform application selection, and signal funder priorities to applicants. There are three main scoring elements or options: the first involves microeconomic factors common to all projects, and the other two provide alternative approaches to evaluating more macroeconomic considerations of broader value to the EPS and EDC, the community and the state. These latter two options include a streamlined, abstracted points-based scoring method, or more detailed CBA methods involving quantification of the costs and benefits to other parties in terms that could be more readily monetized, or are expressed in dollar values. See section C1 for further discussion.

Microeconomic factors: It is important that projects requesting funding provide detailed financial information including both initial costs and costs and net revenues over time (*e.g.*, project term or NPV over 20 years), in a standard format common to project finance with a project *pro forma* balance sheet. This method is based on standard project finance and internal considerations such as CBA, NPV and ROI or (simple) payback periods, as well as key performance indicators (KPIs) such as $/kW and $/kWh. These factors could help define what amount of grant support or capital contribution could make a project possible by making it financeable, or more economical. In addition to standard project financial metrics, supplemental characteristics or performance criteria could be considered. Examples include:

- Size of funding request (*e.g.*, per kW)
- Owner / facilities type and criticality
- Describe how critical loads empower mission critical operations
- Duration / seasonality of island mode operation
- Ability to resist specified hazards (*e.g.*, Category I hurricane wind, inundation)

Macroeconomic / public factors: More macroeconomic factors address impacts to parties other than the owner. Examples include:

- Facilities type and criticality, Lifeline sector, interdependencies, etc.
- Benefits to EPS distribution and transmission
- Number and demographic of population served
- Emissions reduction via clean DG and energy efficiency

One challenge of quantifying non-traditional costs and benefits is that there is no consensus standard by which to value the many types of costs and benefits impacts. Two broad categories include:

Streamlined Point Scoring method: See section C1 for further discussion. This method employs a points-based system that provides abstracted scoring values to represent the potential positive and negative aspects of microgrid projects at the macro level, as well as quantifying attributes preferred (or not) by the OER program team. An advantage of this method is reduced effort and complexity, with the attendant disadvantage of reduced accuracy and precision in CBA evaluation. See Table C-1 for a suggested scoring template.

Detailed Economic Evaluation quantification method: See section C1 for further discussion. This method employs standardized techniques for evaluating costs and benefits of DERs and microgrid projects regarding parties other than the project owner, such as the EPS and EDC (*e.g.*, feeder congestion relief or deferred O&M on substations), the community (*e.g.*, value of avoided outages) and the environment (*e.g.*, social cost of carbon). This approach requires significant effort and detailed analysis, and selection of reference techniques and metrics to quantify non-traditional costs and benefits. An advantage of this method is increased accuracy and precision in CBA evaluation, with the attendant disadvantage of increased effort and complexity as well as a lack of consensus on reference standards and metrics. NY Prize takes this approach. The

PUC's Docket 4600 is developing similar metrics for DERs with its Cost/Benefit Framework of methodologies and reference values.

In an administrative program, most or all applications would be for Level 1 facility and Level 2 campus retrofit microgrid projects, as the business model would not yet exist for development of Level 3 community microgrids. Legislative or regulatory changes could enable Level 3 microgrid development. Scoring of Level 1 and Level 2 microgrid proposals could involve primarily microeconomic considerations, which could be complemented by either abstracted scoring or detailed quantification methods. In the case of Level 3 microgrid development, application of more detailed quantification could be more appropriate.

<u>Provide streamlined or preferential administrative and permitting processes</u>

Administrative and permitting documentation and processing times for common islandable-DER-related technologies could be standardized and streamlined in cases as a part of program design. Priority could also be given to microgrid projects for certain administrative processes such as siting and permitting, *e.g.*, by enabling applicant projects to move to the head of the queue. Similar support could be provided by the EDC, *e.g.*, prioritized response by requests for energy use data, distribution infrastructure information, interconnection and load studies, etc. Program-created microgrid planning guides that define permitting and other administrative requirements, along with document templates, could facilitate project development. Such measures could help simplify and streamline project development for all concerned.

Modifications to permitting processes should be undertaken with care, to allow that critical public interests (*e.g.*, environment, land use, justice) that are vetted in a permitting process must remain a priority. The recommended emphasis is on modifications to shorten the permitting processes via standardization, facilitated access to utility data, clarifications as precedents to reduce uncertainty, prioritized processing, and similar administrative changes.

Examples could include:

- *Interconnection applications*: Streamlined interconnection applications such as pre-approval for certain microgrid design configurations, technologies and protective measures might be developed in advance of program roll-out. For example, specified technologies and protective features for installations that will connect to distribution circuits of a designated capacity could be considered. Lists of pre-approved equipment or template one line diagrams with required safety features could be created as part of program development. This approach runs the risk of favoring certain equipment manufacturers over others. Nevertheless, it could be very helpful to provide pre-approved microgrid design configurations to standardize and accelerate interconnection applications. Applicants for microgrid funding could be encouraged to employ one or more pre-approved modular DER microgrid configurations. Microgrids could help with the challenges of interconnecting the high levels of renewable energy capacity called for in state policy in a safe and expedited manner, potentially providing improved management and control of large blocks of renewable capacity in microgrid configurations.

- *REG program installation configurations for grid-independent operation*: The REG program uses a feed-in tariff; participating PV installations are typically connected to the distribution system directly with a dedicated production meter, rather than being installed behind the customer meter as occurs in many net metering programs. PV installations that receive REG program support would need to be configured with some type of switch as well as an appropriate type of dynamic inverter to enable them to serve facility critical loads during grid-independent operation.
- *Battery energy storage systems*: As part of program design, the program team could review energy storage (ES) and particularly battery energy storage system (BESS) market barriers, issues that lack clarity or clear precedent, and unanswered questions. (This could be a good topic for an RFI.) Examples might include whether or not the EDC can own ES; uniformity *vs*. diversity in policy and management of different BESS chemistries and designs; siting issues (*e.g.*, indoors *vs*. outdoors or rooftops); how a BESS might be treated in the context of a REG or net metered installation (*e.g.*, allowances *vs*. prohibitions, interconnection); and approved forms of aggregation into controllable virtual entities of at least 1 MW capacity to enable participation in ISO-NE ancillary services markets. Advance decision making and enhanced clarity could facilitate ES and microgrid installation planning and development.
- *Siting and permitting prioritization*: Although many permits are administered at the local level, some siting and permitting processes could be streamlined by moving microgrid projects to the head of the line of pending applications. Requiring microgrid funding applicants to employ technologies that meet specified equipment performance criteria could speed approvals. For example, any new diesel generators could be required to comply with Tier 4 emissions control standards to facilitate permitting as well as increased run hours and minimized air quality impacts. The ability of microgrids to provide local-level control over larger, aggregated blocks of DER capacity potentially could facilitate local permitting, as could state-level support.

Consider award disbursements based on milestones

Consider providing initial disbursements of award funds, with further disbursements tied to project milestones. For example, 1/3 of an award could be provided upon award with 2/3 provided upon project completion. Up-front funding disbursements of a portion of the funding upon award will help municipalities and their contractors with project development. Please note that this approach could put program funds at risk, and contractual measures could be undertaken to reduce programmatic financial exposure to project-level risks. Final disbursements should come only after thorough commissioning and islanding testing of a microgrid installation.

Commissioning must be complete to receive full funding

Commissioning (Cx) of microgrid installations is vital and should include full-load functionality testing of all major microgrid systems at every stage of operation: from grid-parallel, through disconnection or islanding from the EPS, grid-independent island mode, and reconnection to the EPS. The authors recommend that final funding disbursements should not occur until the project has been thoroughly commissioned and accepted by the owner.

Require performance evaluation and data monitoring and collection annually or in real time for contract term

Funded or designated microgrids could be required to meet specified performance metrics, and to provide annual reporting or real-time data access.[235] A minimum requirement would be compliance with IEEE 1547.4 *Standard for Interconnecting Distributed Resources with Electric Power Systems*. Consider requiring microgrid performance data to be made available with annual reporting or online access as a condition of program funding awards. This could spur marketplace learning.

2.4. Legislative – Potential enabling legislation

Potential legislative actions that could support microgrid development include:

Expand DG / DER program support

Rhode Island has a number of programs and incentives that support DG and DER development. These could be enhanced to facilitate microgrid development, and in cases could apply only to islandable DERs in a microgrid configuration. If microgrids are determined to provide value as assessed by emerging valuation methods such as are in Docket 4600, the program could reinvent DER incentives to support microgrid development. Better aligning the EDC business model with DER deployment objectives, potentially reinforced with performance based incentives, are among the options to help rethink DG support programs to support microgrid development (see section 2.5 for further discussion).

Stronger policy support and incentives can have significant effects. A rough state-by-state comparison is indicated by the USDOE CHP Installation Database.[236] NY CHP incentives include net metering eligibility, more dollars per kW than in RI, and robust demand response program opportunities, plus some utilities offer special CHP gas rates; these factors contribute to the 585 CHP installations, including 220 islandable “critical infrastructure” (CI) installations.[237] MA CHP policies include net metering eligibility, with 210 CHP installations including 81 CI.[238] CT classifies CHP as a Class III renewable eligible for net metering and virtual net metering; CT has 188 CHP installations including 79 CI.[239] RI has 26 including 13 CI.[240]

[235] For further discussion with examples see CEG/RPP, *What States Should Do*, June 2015, p.24.
[236] https://doe.icfwebservices.com/chpdb/
[237] https://doe.icfwebservices.com/chpdb/state/NY
[238] https://doe.icfwebservices.com/chpdb/state/MA
[239] https://doe.icfwebservices.com/chpdb/state/CT
[240] https://doe.icfwebservices.com/chpdb/state/RI

Opportunities include:

Provide feed-in tariff for islandable DERs: The REG program feed-in tariff could be modified or complemented to provide a higher rate for approved islandable DERs. Alternately this could be reflected in higher ceiling process for microgrid DERs in the REG program.

RECs or other production-based revenue for CHP power and/or thermal output: The EDC's incentive program provides capital cost contributions for CHP systems. A per-kWh incentive for islandable CHP system power production would further strengthen financial support. Policies, programs and funding support recommended and developed by OER's Thermal Working Group (TWG) might be a source of CHP support[241]. Similarly, microgrids thermally-related policies should align with TWG policies.

Expanded net metering: Net metering could be expanded, for example with value based compensation at potentially higher levels than retail rate offset, as per Docket 4600 and other methodologies.

VNM for expanded set of eligible generation, beneficial accounts and multiple customer classes: Expanding VNM for designated microgrids could include a larger number of generation types, a larger set of beneficial accounts (*e.g.*, 10+), and potentially higher compensation as per new value-based methodologies such as in Docket 4600. This would help support typical "blue sky" operations of larger DER systems, which could power more significant critical loads during outages. In statute PA 13-298 CT enabled VNM for Class I and III (CHP) renewable energy generation of up to 3 MW, to assign credits to up to 10 beneficial accounts that are public facilities included in a municipal/state microgrid. Expanding VNM to include both public and private sector critical facilities that are part of a designated municipal or community microgrid could provide public agencies with a basis for cost recovery of delivered energy. For example, if allowed by law, potentially a municipality or other public entity might be able to charge a fee to a set number (*e.g.*, five) third-party critical facilities included in a publicly-owned microgrid, in consideration of the value of delivered energy.

Community aggregation: The Community Net Metering (CNM) and Community Remote DG (CRDG) programs are new options in 2017[242]. Consider modifying these programs to fund larger-scale PV or wind turbine systems, and potentially add energy storage and CHP systems, which would be configured to serve one or more critical facilities in grid-independent island-mode during outages. The CFs served might or might not be among the beneficial accounts for CRNM.

[241] http://www.energy.ri.gov/efficiency/thermal/
[242] For information on Docket 4631 re Community Net Metering see (http://www.ripuc.org/eventsactions/docket/4631page.html).

Include microgrids in RES or as a stand-alone mandate, with incentives

The state could include islandable DERs in the Renewable Energy Standard (RES), with supporting incentives or mandates. The EDC could be required to purchase or otherwise support islandable DERs; note that this could require PUC approval. This approach could use or modify or emulate the REG feed-in tariff, allocated over 15 year terms on a per-kWh basis. The EDC's CHP incentive program could provide a higher level of funding support for islandable systems on a per-kW basis (as it is now), and/or potentially expand to include purchase support for produced energy.

To cite the Clean Energy Group: "Incentives could take the form of higher capacity caps, accelerated incentive payments, incentive adders or multipliers, or carve-outs similar to SRECs (renewable energy credits specifically for solar PV). [….] Mandates would require utilities to procure resilient power capacity up to a set target or defined percentage of the utility's portfolio."[243] For further discussion with examples, see CEG/RPP, *What States Should Do*, June 2015, pp. 28–30.

Enable approved microgrids to distribute power across public ROW and utility easements

Legislation that explicitly allows critical facility microgrid developers to distributed power across a public right of way or a utility easement would address a significant barrier to development of Level 2 campus-type microgrids. This could enable the formation of a "virtual campus" comprising facilities that have conducive circumstances for shared energy systems, such as complementary electrical and thermal load profiles. As with other proposed exceptions to the current regulatory context, it could make sense to limit this ability to projects that meet a narrow definition of a designated municipal or public purpose microgrid. If an expansion of VNM is also authorized in designated circumstances, then perhaps this and other exceptions or special incentives could align with each other, for example in their applicability to a capped number of facilities within a given microgrid (*e.g.*, ten). Such a cap could allow for a waiver enabling a modestly larger number of facilities in cases deemed appropriate by the OER microgrid team.

CT enabled designated municipal microgrids to distribute power across a public ROW from Class I and Class III (CHP) generation sources under 5 MW in statute PA 13-298. The NJBPU 2017 microgrid report suggested a policy where microgrid developers would have to fund electrical infrastructure that crosses a public ROW but then turn over those wires etc. to the EDC to own and maintain, which could provide a way around this perceived barrier[244]. CT's microgrid program also states that the EDCs own electrical distribution infrastructure within microgrids, but that requirement has proven fuzzy in practice.

[243] CEG/RPP, *What States Should Do*, June 2015, p.28.
[244] NJBPU, *Microgrid Report*, 2016, p.79.

In a letter to the NJBPU, the League of Municipalities submitted a letter stating their position that municipalities are in a superior position to utilities regarding the granting of easements and ROWs, and asserted the right of municipalities to distribute power across ROWs for microgrid development.[245] RI could review the in-state status or applicability of this assertion.

The Mass CEC helped fund a study by Harvard Law School of the issue that concluded that there was no statutory barrier to municipalities distributing power across a ROW.[246] OER could undertake a similar review of RI law.

<u>Create enabling structures to facilitate economical and legal and low-risk project development behind the meter (BTM)</u>

The state could consider legislation enabling special purpose entities or modifications to existing programs to create or expand financing and procurement options for microgrid development by public agencies in particular. Potential approaches include:

Energy Improvement Districts or similar structures: Municipalities have long employed tax credits, Tax Increment Financing (TIF), business improvement districts, special zoning, and similar strategies for economic development. Variants of these strategies could be used to support microgrid development.

CT enabled municipalities to create an Energy Improvement Districts (EID) via statute PA 07-242. An EID is a tax-exempt entity with a municipally-chartered Board of Directors that can develop and operate distributed energy resources including generation of up to 65 MW, CHP, and energy efficiency investments. An EID can issue revenue bonds and charge fees for energy. Subsequent legislation PA 13-298 enabled EIDs to finance, own, lease, or contract for development and operation of microgrids. The MA microgrid report recommended a similar approach to enable Energy Reliability Districts (ERDs) to promote development of safe havens during disasters. The legal framework for ERD formation would be developed via a multi-stakeholder process. See MA microgrid report section 10.3.

Expand RIIB C-PACE program scope for defined microgrids: The RIIB and its C-PACE program already provide a versatile support for microgrid investments in applicable facilities. In effect RIIB already can serve as a “resilience bank” to a certain extent, akin to the equivalent institution in NJ. A revolving resilience loan fund could be created for similar applications, for example administered by the OER microgrid program team. Potential expansions of these capabilities could include:

- Expand C-PACE eligibility to other owner types in defined microgrids.
- Allow C-PACE-eligible properties to contribute to financing shared energy systems, even if they are not the host of the DERs to which they are connected (*e.g.*, use a C-PACE

[245] NJBPU, *Microgrid Report*, 2016, pp.80, 105–107.
[246] http://environment.law.harvard.edu/wp-content/uploads/2015/08/masschusetts-microgrids_overcoming-legal-obstacles.pdf

assessment to help fund electrical and thermal distribution systems, and even a portion of the connected source DG "prime mover" and appurtenances, even if those systems are located on another property).

- Allow municipal entities that are in a long-term contract with a microgrid host to benefit from VNM by assigning the value of DG credits to municipal accounts that do not host the microgrid DG. See MA microgrid report section 10.3.2, page 10-8 to 10-9.
- Allow credit enhancement as a financing option (*e.g.*, buying down borrowing rates or helping underwrite loans).
- Include resilience enhancements such as flood proofing as allowable investments.

2.5 Regulatory – Potential PUC actions

Please note the authors' cautionary comments in section 2.2 regarding making potential fundamental changes to the regulatory regime for the primary motive of microgrid policy. Discussion of the PUC role in an OER-directed microgrid program and any attendant legislative actions could begin with the PUC role in administrative and legislative actions described above, where dockets and rulings are required and appropriate. PUC actions and issues that potentially relate to microgrid development are discussed below.

Inducing changes in EDC behavior can be accomplished via mandates and/or incentives such as performance-based regulations. Requirements can convey greater certainty of achieving desired outcomes, yet risk high costs, unintended consequences and stakeholder (*e.g.*, EDC) alienation. Effective incentives can help align commercial interests and investment with public policy objectives and promote least-cost achievement of desired results. Successful incentive program design is challenging in the complex context of regulated network industries and risks unintended consequences akin to mandates, though perhaps with different mixes of winners and losers (*e.g.*, ratepayer interests could suffer, or others). We will use the term "incent" (the EDC) to mean "provide an incentive to" (the EDC) to encourage it to take a desired action.

A detailed exploration of the issues, risks and trade-offs around mandate or incentive design for the EDC in Rhode Island is beyond the scope of this report. Actions that provide the marketplace with greater transparency, access to information and reduced risk tend to encourage investment and efficient market outcomes; the challenge remains to align those outcomes with public interests. An option that can benefit both customers and the EDC is programmatic action to increase deployment of DERs in locations that provide both cleaner energy services and energy assurance to customers, as well as reducing EPS capital and operating costs, *e.g.*, via deferred transmission and distribution (T&D) investment.

It is not clear what performance metrics could be used to motivate an EDC to enable microgrids. Development of effective metrics could be a beneficial early step to be included in a future PUC proceeding or state-sponsored stakeholder process that addresses performance regulation. Docket 4600 contributes to the development of shared metrics and methods for evaluating the full value of DERs in T&D planning and operations.

There are numerous other aspects of marketplace regulatory structure to consider in enabling Level 3 microgrids. One aspect is questions around the status of customers that are within Level 3 microgrids that would require careful deliberation. For example, how does a Level 3 microgrid differ—or not—from a Level 1 or 2 microgrid or a single-facility CHP installation, *e.g.*, with regard to tariff structure? What is the status of customers in a Level 3 microgrid configuration? By allowing themselves to be served in this way, have they given up anything regarding how the PUC/DPUC considers their interests? Would the Attorney General have default authority in this circumstance that it would need to pay attention to in ways that would not occur for routine utility-customer disputes that would normally be handled by the PUC//DPUC? If a residence or a small business is in the microgrid, what if anything changes for it and its occupants? These are just some of the issues to be clarified in any comprehensive, careful marketplace re-design.

Current PUC activities that relate to potential microgrid development

A few of the recent or current issues and dockets under PUC consideration include the following:

Master meters: A statutory issue that relates to the PUC is the recent interpretation of the law to disallow master metered accounts, *e.g.*, in multifamily housing. Existing buildings with one master meter rather than individually-metered apartments are likely to be grandfathered, but evidently this configuration will be barred going forward. Master meters facilitate DER and microgrid project development by simplifying net metering, interconnection and power provision, relative to having to address each of many individual apartment meters, with attendant complexities of tenant agreement and turnover.

Docket 4600[247]: This Docket includes development of a Cost/Benefit Framework with reference methods and metrics to broaden the scope of quantifiable factors in distribution system planning, *e.g.*, by adding societal and environmental benefits and impacts. Eventually this approach could be expanded to address many aspects of DERs and EPS planning decisions, potentially including microgrid project factors. If evaluations indicate that a microgrid provides greater value than it costs based on its location and performance, that could provide a basis for the program to authorize or enable the microgrid to utilize support policies to deliver that value.

Time varying rates: Development of time-varying or "Time Of Use" (TOU) rates would require the EDC to install Advanced Metering Infrastructure (AMI). Currently, RI has only Automatic Meter Reading (AMR) technology that enables wireless meter reading by EDC representatives, but not AMI "smart meters" that enable two-way communication between the meter and the central system, record consumption of electric energy in intervals of an hour or less, and communicates that information at least daily back to the utility for monitoring and billing.[248] TOU rates could benefit microgrid-related technologies such as energy storage. (Also, AMI could facilitate microgrid feasibility analysis by providing interval data that is very useful for DER planning. Some smart meters can be used to shed load within microgrids by shutting off power supply to metered facilities upon remote command.)

[247] www.ripuc.org/eventsactions/docket/4600page.html
[248] https://en.wikipedia.org/wiki/Smart_meter

Require, incent or enable the EDC to provide information on potential locations for microgrid development of greatest value to the EPS

The PUC could require or incent the EDC to provide information about the costs and benefits to the EPS at the distribution and potentially transmission levels, to inform microgrid planning. This information could be made available solely to the OER microgrid team to inform evaluations of funding applications. Alternately or additionally, this information could be made available to the marketplace in at least a generalized level of detail, either upon request at a project-specific level or in the form of publicly-identified areas that would benefit the most from microgrids, akin to the "opportunity zones" identified by NYSERDA for the NY Prize competition. Animating the marketplace fundamentally requires more of this type of transparency about local EPS system conditions to inform microgrid feasibility analysis and funding applications. It seems probable that secure and sensible means could be devised to share with microgrid developers upon request a measure of economically-relevant information about T&D infrastructure condition, capacity, capital planning and operating costs without compromising critical infrastructure security. It could be argued that if EPS security concerns are so significant as to keep this kind of information secret, then that is a strong indicator that the need for resilient microgrids is a security imperative.

An equivalent or related process has been conducted in the development of evaluation metrics by the EDC and EEMC in the context of the Least Cost Procurement law, to inform identification of non-wires alternatives (NWAs) in T&D planning. Docket 4600's Cost/Benefit Framework also provides reference metrics and methods.

Require, incent or enable the EDC to create custom tariffs for cost recovery and/or rate risk reduction in microgrid locations, and/or for microgrids to monetize sources of value that they provide to the EPS and EDC

This topic is a core issue for regulatory modifications concerning microgrids, and for both assessing and addressing the full costs and benefits of DERs in relation to the EPS and the EDC. Microgrids and their DERs provide benefits to the EPS as well as impose costs and their full net value should be compensated, just as the costs they impose on the system should be recovered. These issues lie at the heart of the evolving debate about the emerging opportunities for the grid to become more of a two-way "transactive platform" for exchanges of monetized costs and benefits between customers, the EDC, and third party providers of goods and services.

A detailed exploration of the issues, risks and trade-offs of these aspects of market re-design in Rhode Island is beyond the scope of this report. Yet it seems possible that the issues around microgrid custom rate design; value-based compensation for benefits to the T&D system and services provided to the EDC or ISO; and cost/benefit monetization are aspects of regulation that could be explored and restructured without the Pandora's Box risk of modifying fundamental aspects of the regulatory regime without a comprehensive process akin to NY REV. The DER valuation basis that can be applied to such transactions are already under development in Docket

4600 and elsewhere. It would be important that the services sold in each direction are identified, evaluated and priced in a consistent, fair and transparent way.

Custom tariffs that are customer- or project-specific enable the EDC to recover costs from those customers who will most directly benefit from a microgrid. This is arguably more equitable than, and preferable to, socializing the costs across all customers statewide by adding them to the EDC's rate base. Please note that there may be some precedent for rate-basing investments in localized EDC improvements in the context of LCP and NWA.

The EDC already has at least one option to apply a custom tariff for enhanced reliability, by adding a second feeder for N+1 redundancy (ideally one originating from a different distribution circuit than the primary service feeder). This capability might already enable the EDC to develop reliability enhancement custom tariffs for other types investments, possibly including microgrid-related investments such as hardening or other modifications to distribution infrastructure connected to—or within—a microgrid. OER and the PUC could conduct a review of possible custom tariff types to support microgrid development, for example for Level 1 and Level 2 microgrids. One option could be to develop a menu of pre-approved microgrid support tariffs as part of a state program. Another could be to provide a microgrid service charge-type rider.

For one example of a custom tariff proposal for a Level 3 multi-user community microgrid, see National Grid's NY Prize proposal to develop a hybrid microgrid in Potsdam, NY. (Note that this project proposal has evolved since the initial proposal filing and current details might differ.)

One downside risk is that development of a custom tariff might come relatively late in project design due to the need for specific cost information, but then might be judged by the customer as being too high. This risk might apply in particular to Level 3 community microgrid projects, where there is a burden of community engagement and explication upon elected officials to prepare their residents for potentially higher energy costs in return for greater reliability.

Another potential enabling policy for microgrid development would be to allow the EDC to enter into project-specific long-term fixed-rate contracts (10–25+ years) to reduce tariff variability risk and facilitate microgrid financing.

<u>Require, incent or enable the EDC to procure energy from resilient islandable DERs</u>

This could be accomplished by expanding or modifying the RES, REG feed-in tariff, EDC CHP incentives or other applicable DER incentive programs. For further discussion, see sections 2.5.

<u>Require, incent or enable the EDC to use on bill financing for microgrid investments</u>

National Grid's On-Bill Financing (OBF) programs for small business (<200 kW) and Large Commercial & Industrial (LCI, >200 kW) customers provide 0% financing over a 12–24 month period. This program could be expanded by extending the range of eligible measures, eligible customers, and repayment term duration to support microgrid development. EDC provision of on-bill financing for customer microgrid investments could complement a custom tariff. This could apply to a subset of microgrid assets, *e.g.*, load reduction, or electrical distribution equipment modifications on either or both the customer or EDC side of the meter (particularly where the EDC is the ultimate asset owner).

Require, incent or enable the EDC to own or contract for generation and/or storage, in excess of 15 MW cap

An alternative or possibly complementary approach to "animating the marketplace" could be for the state to expand the ability of the EDC to own or contract for generation and storage, giving the EDC a more direct role in Level 3 multi-user microgrid ownership and development. This approach would entail fundamental alteration of the regulatory regime and is not recommended in the absence of a NY REV-type comprehensive re-examination of the current model. The NY Prize microgrid competition includes projects where EDCs can participate in hybrid ownership models, contract for generation, and develop microgrid-specific custom tariffs. MD's Microgrid Task Force recommended that third party developers be allowed to compete with the EDCs to develop multi-user "public purpose" microgrids if the EDCs did not develop such microgrids, in the context of numerous other changes.

Although giving the EDC marketplace primacy or the exclusive ability to develop Level 3 microgrids seems like one of the simplest strategies for achieving EPS decentralization, it also represents a big step backwards from the electricity sector restructuring of the 1990s that defined the EDC model, towards the historical vertically integrated utility model that remains in place in 27 states. Giving the EDC marketplace equivalency to private sector microgrid developers (as MD has considered) might spur competition, but carries significant anti-competitive risk due to the many advantages that EDCs would have over competitors (*e.g.*, control over access to EPS information, veto power over interconnections) in the absence of substantial compensatory changes.

If the state were to decide to go in this direction, policy options are outlined below. Currently the EDC is allowed to own a maximum of 15 MW of DG. Modifications to this policy could include:

- EDC-owned DG could be allowed to serve critical facility microgrid loads (*e.g.*, at the facility or feeder/substation level), in grid-connected parallel "blue sky" operations and/or in island mode during outages.
- EDC could be allowed to own energy storage that can serve microgrid loads akin to DG, as described above. MA recently concluded that its laws and regulations enable EDCs to own energy storage; OER could review its legal framework in the same regard.
- The 15 MW cap on DG ownership by the EDC could be raised, and/or EDC investment in microgrid DG could be an exempted from the cap.
- EDC could be allowed to contract for microgrid-component DER production (*e.g.*, via a PPA or similar contract) and wheel that energy to customers via standard or custom tariffs. For an example of a similar arrangement for a Level 3 multi-user community

microgrid, see National Grid's NY Prize proposal to develop a hybrid microgrid in Potsdam, NY. (Note that this project proposal has evolved since the initial proposal filing and current details might differ.)
- The EDC could be able to sell services from its microgrid DERs (*e.g.*, generation capacity, frequency regulation, demand response, etc.) into the ISO-NE energy marketplace and to microgrid customers, if it is not able to do so already.

Require, incent or enable the EDC to participate in utility-directed and/or hybrid microgrid models

See the cautionary discussion in 2.5.6. In a utility-directed microgrid, the EDC owns and operates the microgrid assets, including generation and storage. In a hybrid microgrid ownership model, the EDC shares ownership of microgrid assets with a third party, *e.g.*, the EDC might own the distribution network and controls while a third party owns the generation. One strategy could be to enable differently-regulated EDC subsidiaries to play a role in project development.

NY Prize and NJ mandate some utility role in Level 3 microgrid planning and/or ownership. MD is considering proposals by Baltimore Gas & Electric (BG&E) to form utility-owned microgrids in commercial centers by modifying its distribution infrastructure and adding standby diesel or natural gas fueled BUGs.

Exempt microgrids from PUC regulation that are publicly-owned or below a size cap

The PUC could explicitly exempt from utility and/or rate regulation designated critical facility microgrid projects that are either or both:

- Owned (or leased or contracted for) by a public entity such as a municipality or state agency
- Below a designated size, *e.g.*, 10 MW of generation or a cap on maximum load served

The PUC could set requirements on these designated exempt classes of microgrids, including:

- Demonstrated public benefit, *e.g.*, inclusion of Lifeline sector critical facilities or emergency shelters
- Ability to safely disconnect and reconnect from EPS and operate in island mode for a specified period
- Demonstrated and auditable lack of harm or contrary interest to any customer rate class
- Obligation to serve connected customers

These exemptions could include both electrical and thermal energy, such that heating and cooling shared energy systems based on CHP are provided the ability to distribute and sell heating or cooling energy to multiple customers, and/or are exempted from regulation within designated performance parameters or applications. For further discussion, see NYSERDA 2010 pp. 101–102.

MD's microgrid task force report recommended consideration of similar actions. With regard to "Town Center" Level 3 multi-user microgrids, the NJBPU microgrid report noted one approach to regulatory exemptions for Level 3 microgrids: "Rate Counsel's position was that while the above [set of principles] was a potentially workable technical option for the operations of an advanced microgrid for critical facilities, the Governor would have to declare an emergency in order for the advance microgrid to operate. In that case, under an emergency declaration, the operations of an advance microgrid would not be a public utility. Other than that situation, the advanced microgrid would need to be regulated as a public utility."[249]

Enable non-utility third parties to own and operate Level 3 multi-user microgrids

Enabling third parties to compete with the EDC in providing energy services and owning and operating microgrid DERs and distribution infrastructure could constitute the greatest change to the regulatory regime, and as such would be considered via a comprehensive process akin to NY REV. The regulatory status of such third party owner/operators would require PUC authorization, with regard to issues including: would they be regulated as utility or non-utility entities, would projects below a certain size be exempt from utility regulation, etc. MD is considering such an approach, with both EDC and third party opportunities for microgrid ownership, and hybrid models such as "Local Microgrid Operators" that utilize EDC distribution infrastructure.

A variation on this approach could involve pathways to municipalization or cooperative ownership models.

[249] NJBPU *Microgrid Report*, 2016, p.80.

PART E: MICROGRID PILOT PROGRAM CASE STUDIES

1. Background

The Rhode Island Office of Energy Resources (OER) requested that this report include two case study applications of the Cost Benefit Analysis Model (CBAM, see Section C) in low to moderate income (LMI) multifamily housing (MFH). OER considers these sites as candidates for pilot project funding as demonstration Level 1 single-facility, single-meter microgrids.

The authors and OER worked with Rhode Island Housing[250] to identify two pilot project candidate facilities: Babcock Village (BCV), 122 Cross St, Westerly, RI, owned by Property Advisory Group-Cathedral Development Group (PAG)[251]; and Oxford Place (OXP), 200 Gordon Ave, Providence, RI, owned by Preservation Of Affordable Housing (POAH)[252].

The authors conducted site visits, analyzed utility usage data, and reviewed architectural and engineering plans, previous energy studies, and other information including input from National Grid's interconnection team. This research informed development of conceptual designs for retrofit Distributed Energy Resources (DERs) and associated controls, switchgear and other equipment to enable grid-independent operations and convert these properties into Level 1 single-facility microgrids. Our team considered both solar photovoltaics plus battery energy storage (PV+BES), and natural gas fueled reciprocating engine combined heat and power (CHP) or cogeneration systems.

The authors conducted a high-level feasibility analysis on these conceptual designs using HOMER Pro microgrid planning software and the Cost Benefit Analysis Model (CBAM) tool used for this report (see Sections C and E1.1). This high-level feasibility assessment represents an informed estimate of potential microgrid costs at a general level, and we describe representative procurement options and grant funding scenarios based on the models and results. Our analysis considers only "microeconomic" factors at the level of the projects, and does not evaluate "macroeconomic" factors such as costs and benefits to the grid, society and the environment (see Sections A2 and C1 for further discussion). Please note our caveat that this is generalized analysis based on very preliminary design with rough estimates, numerous assumptions, and unanswered questions that would require research and engineering design work that is beyond the scope of this report. Accurate and precise investment-grade analysis based on final design work would be developed in pilot project implementation.

The feasibility analysis case studies are discussed below, with one section for each facility.

[250] www.rhodeislandhousing.org/
[251] http://propertyadvisorygroup.com/
[252] www.poah.org/

1.1. HOMER analysis and relationship to CBAM modeling

The authors used Hybrid Optimization of Multiple Energy Resources (HOMER) Pro 3.8.4 version software[253] to evaluate Distributed Energy Resource (DER) options for the two pilot projects. HOMER is a microgrid analysis tool developed by the U.S. National Renewable Energy Laboratory (NREL). It allows modeling of various microgrid technologies to determine the lowest cost of energy solution given a number of inputs, including information about the resources generating electricity and the facilities whose loads are served. HOMER is not required; any source of design that predicts microgrid DER output on a monthly basis will suffice. Two similar programs are RETScreen Clean Energy Management Software[254] and LBNL's Distributed Energy Resources Customer Adoption Model (DER-CAM)[255] tool.

The CBAM inputs used to evaluate the two pilot facilities are a combination of the same inputs used in the HOMER analysis and the outputs of that model. The cost figures, electric and thermal loads, and electricity prices match those fed into HOMER. The monthly production of the various sizes and types of generation is taken from the outputs of the HOMER. HOMER is not needed to replicate this process for future facilities; it is merely used to create those generation profiles for these case studies.

HOMER optimized the size of battery storage for each facility based on an algorithm that minimizes net present cost. For these CBAM case studies, however, the size of the battery bank should reflect desired resilience characteristics. Batteries are sized here to serve the peak facility load for a 4 hour duration; this time period does not reflect any case-specific requirement.

Table E-1: BCV and OXP battery sizing

Facility	Peak Load (kW)	Battery Size (kWh)
Babcock Village	43 kW	172
Oxford Place	92 kW	368

As in HOMER, two scenarios are analyzed for these facilities: solar PV plus storage and small scale CHP. Costs for the various generating assets match those in HOMER, with the addition of electrical infrastructure cost.

The CHP scenario assumes net metering cannot be utilized and there is no eligibility for payment for excess generation, but the systems are sized economically, *i.e.*, they are sized to meet thermal base load rather than the full facility load. The CHP scenario also affects thermal energy costs relative to the baseline, as the CHP unit increase natural gas consumption but also displaces some of the baseline boiler natural gas use by providing byproduct heat.

[253253] www.homerenergy.com and www.homerenergy.com/HOMER_pro.html
[254] http://www.nrcan.gc.ca/energy/software-tools/7465
[255] https://building-microgrid.lbl.gov/projects/der-cam and https://eetd.lbl.gov/software/389/der-cam

The solar scenario assumes a Renewable Energy Growth (REG) program feed-in-tariff (FIT) of $0.225/kWh of PV production. It ignores baseline costs for thermal generation, because the solar array isn't adding anything except electricity generation.

Table E-2: BCV and OXP battery sizing

	Babcock Village			**Oxford Place**		
	Size (kW)	**Capital Cost ($)**	**O&M ($/yr)**	**Size (kW)**	**Capital Cost ($)**	**O&M ($/yr)**
Solar PV	155	387,500	1,550	100	250,000	1,000
Batteries	172	91,848	1,720	368	196,512	3,680
Inverter	63	15,876	-	58	14,616	-
CHP	35	157,500	10,352*	100	450,000	41,763*
Electrical Infrastructure	-	22,600	-	-	45,200	-

**These figures are based on a contract that is pegged to the Consumer Price Index. They are left as such for the HOMER analysis, which also accounts for inflation. They are adjusted for the CBAM, which uses base year dollars.*

The cost of added electrical infrastructure needed to enable islanding capability is estimated based on figures given by a range of sources. The cost is heavily dependent upon the type and size of electrical equipment needed, configuration of existing infrastructure, age and condition of existing electrical equipment, size of microgrid, and number of facilities. The numbers used here are adjusted and scaled from a microgrid component cost estimate provided in the report *Microgrids: Benefits, Models, Barriers and Suggested Policy Initiatives for the Commonwealth of Massachusetts*.[256] Electrical infrastructure costs will become more precise as design progresses.

<u>Babcock Village case study</u>

2.1. Existing conditions

Overview: Babcock Village (BCV) is a low to moderate income (LMI) multifamily housing (MFH) facility located at 122 Cross St, Westerly, RI, owned by Property Advisory Group-Cathedral Development Group (PAG). This facility has 152 units of elderly and LMI housing, including roughly 10 residents who are oxygen-dependent. The site is in an area of minimum flood hazard, located about 2500 feet west of an "A" 1% event flood zone on the east side of Route 78. The "W"-shaped three-story building was built in 1981. It comprises two identical "L"-shaped wings with about 75 residential units each and "mirror image" floor plans, connected at a central area with a community room. See Figures BCV-1 and BCV-2.

[256] MA 2014, p. 7-3, Table 7-1: Range of Costs for Microgrid Components, accessed at: http://files.masscec.com/research/Microgrids.pdf

Figure BCV-1: Babcock Village, overhead view with north at top.

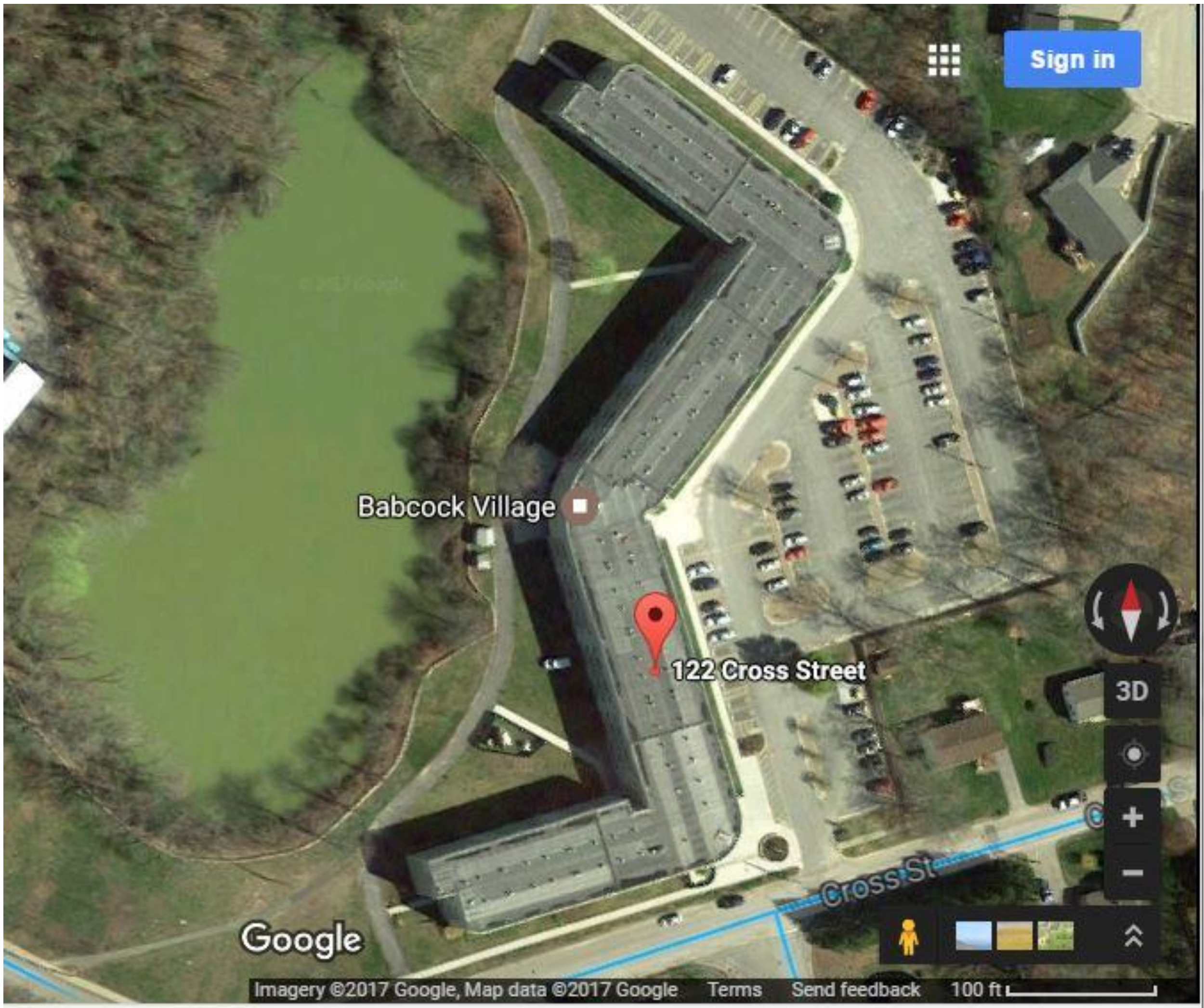

Image adapted from Google Maps.

The flat roof is in good condition and is about 8 years old with a planned 20 year life. Double rows of exhaust outlets running down the middle of each roof segment, as well as two HVAC rooftop units (RTUs) somewhat reduce the amount of usable surface area for a PV installation.

Figure BCV-2: Babcock Village ground floor plan, north at top.

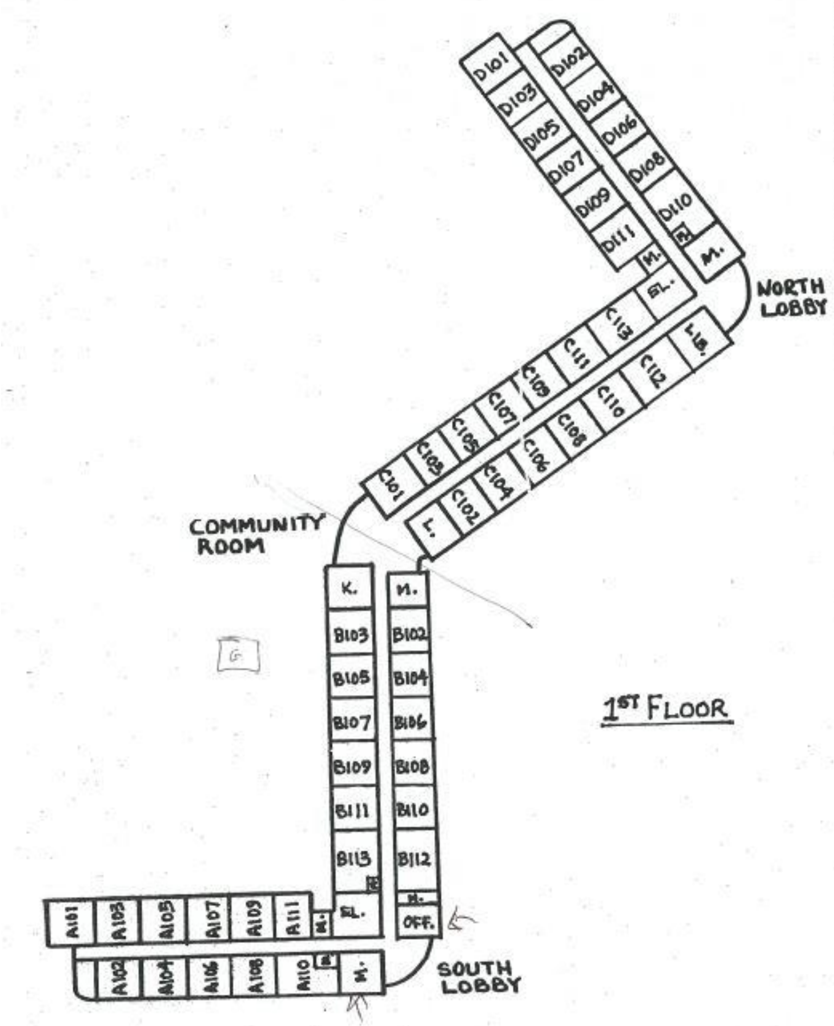

Image courtesy of PAG.

Mechanical and electrical systems: The building has 150 individually-metered apartments, plus a "house" meter for all electrical systems outside the apartments. Each wing has a dedicated mechanical room with two natural gas-fired cast iron boilers and two VFD-controlled 5 HP heating hot water (HHW) circulation pumps. The South mechanical room is at the natural gas and electric power service entrance, and contains the electric meters and main panels and switchgear. Natural gas is piped to the North mechanical room that contains two boilers plus the domestic hot water (DHW) heating system for the entire facility. One boiler provides HHW only; the other provides both HHW and DHW, heating the DHW via a refrigerant heat exchanger (HX). There is no central cooling; roughly two-thirds of the residents have installed "sleeve insert" air conditioning units. The building has two elevators (one per wing), each driven by a 25 HP motor. In recent years, exterior and hallway lighting was upgraded to more energy-efficient LED and fluorescent T-8 technologies.

Backup power and critical loads: The building is served by a 150 kW diesel fueled backup generator (BUG) with a 500 gal fuel tank. This powers a critical loads circuit behind the "house" meter (but not the apartments) which includes life safety and fire protection systems, all boilers, all hallway lighting, 2 elevators, one PAG management office, and the community room lighting, plug loads and small kitchen area with a sink, 2 refrigerators and a microwave. No critical circuit load profile data was available. Because the BUG does not power the individually-metered apartments, during power outages "shelter in place" (SIP) operations are centered in the community room which provides a safe haven with heating, device charging and some food preparation and distribution. Cooling could be provided by plug-in units (*e.g.*, MovinCool spot coolers[257]) if needed. During the blackout caused by Hurricane Sandy in 2012, the BUG ran for 3 days and still had fuel left when electric service was restored.

2.2. Microgrid conceptual design

The facility already has a critical loads circuit connected to a diesel-fueled BUG. The microgrid conceptual design was to install additional clean(er)-energy DERs with controls, switchgear, protective safety measures and other equipment needed to disconnect from the grid and form a Level 1 single-facility, single-meter microgrid. The DERs could provide economic and environmental benefits during normal "blue sky" operations in grid-connected mode, as well as provide energy to the facility's critical loads while disconnected from the grid in "island" mode. No modifications to the facility's existing critical loads circuit were planned other than configuring the DERs to supply that circuit.

In island mode the retrofit DERs would be dispatched first to serve the critical loads, with the BUG shut down and standing by to provide backup power and "black start" capability to the DERs if required. Duration of DER operation would depend upon both the critical load profile and DER energy supply or storage capacity. When DERs could no longer serve the critical loads, the BUG would be dispatched. This configuration could reduce BUG run time, conserve diesel fuel and reduce emissions. Each DER configuration and Sequence Of Operation (SOO) described below would require approval from local Authorities Having Jurisdiction (AHJ) such as the utility and the fire department. We assumed that the described approaches would be approved, for the purposes of this discussion.

The authors considered two types of DERs: solar photovoltaics plus battery energy storage (PV+BES), and small-scale combined heat and power (CHP) or cogeneration with a natural gas fueled reciprocating engine prime mover, discussed further below.

Solar power plus battery energy storage. We developed an estimate of potential rooftop PV capacity that could be retrofit onto the flat roof, with consideration of factors including roof age,

[257] http://movincool.com/

type, structural load-bearing capacity, obstructions, and shading considerations. The PV could be connected via a protective conduit to a ground-level external installation comprising inverters, controls, energy storage, DC and/or AC disconnects (which could be installed on the roof also), protective measures, and other balance of system equipment that could enable grid-independent operations. Battery type and chemistry were not specified.

Under normal "Blue Sky" operations, the PV+BES system could provide economic benefits to the facility by reducing energy costs, primarily due to PV production. The BES probably could not provide significant economic benefits on a daily basis in this case, *e.g.*, by discharging during peak load periods to reduce demand charges; its primary value would be energy assurance during outages. Electric meter interval data was not available to develop a daily load profile. We inferred from BCV's billed peak loads and the occupants' demographics that the load profile would be fairly level, without significant peaks in the morning or evening such as occur in multifamily housing (MFH) where a large percentage of the residents leave during the workday and return at night.

During grid outages that require back up power, microgrid controls and switches would enable the PV+BES system to operate in "island mode" and power the critical loads circuit. The PV+BES system would be dispatched first, with the BUG shut down and standing by. The PV system would charge the BES, and the BES would provide energy to the critical loads. The PV+BES system would lack the capacity to serve the critical loads 24/7; our design was sized to serve estimated peak critical loads for 4 hours. Duration of operation would depend upon PV output and BES capacity and level of charge. When PV+BES could no longer serve the critical loads, the BUG would be switched on. It could be possible to configure the BUG to charge the BES and then switch off until needed.[258]

A 2013 analysis performed for PAG by SPIRE Solar Systems was used as a starting point for the sizing of the solar array. SPIRE recommended a roof-mounted 153 kW array. The array does not take up the full roof area; allowing for panel spacing, roof access, and roof equipment, an estimated 200 kW array could be installed. Despite this excess capacity, a 153 kW was chosen by SPIRE; the authors selected a 155 kW for the HOMER analysis, due to regulatory requirements. PV procurement options include Rhode Island's net metering provisions and the Renewable Energy Growth (REG) program feed-in tariff (FIT). Both programs stipulate that onsite PV capacity cannot produce more electrical energy than the building uses on an annual basis, averaged over three years (essentially the building cannot be a net supplier of electricity). Our design supplies power to BCV's critical load circuit established behind the "house" meter, excluding the individually-metered apartments, so we considered only the "house" meter's consumption. 155 kW is the maximum array size that meets that criterion. See Figure BCV-3.

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[258] Similar design configurations and SOO are employed at Level 1 microgrids including the Scripps Ranch Recreation Center in San Diego, CA and Fire Department Headquarters in Northampton, MA.

Figure BCV-3: Babcock Village rooftop 153 kW PV system plan, north to right.

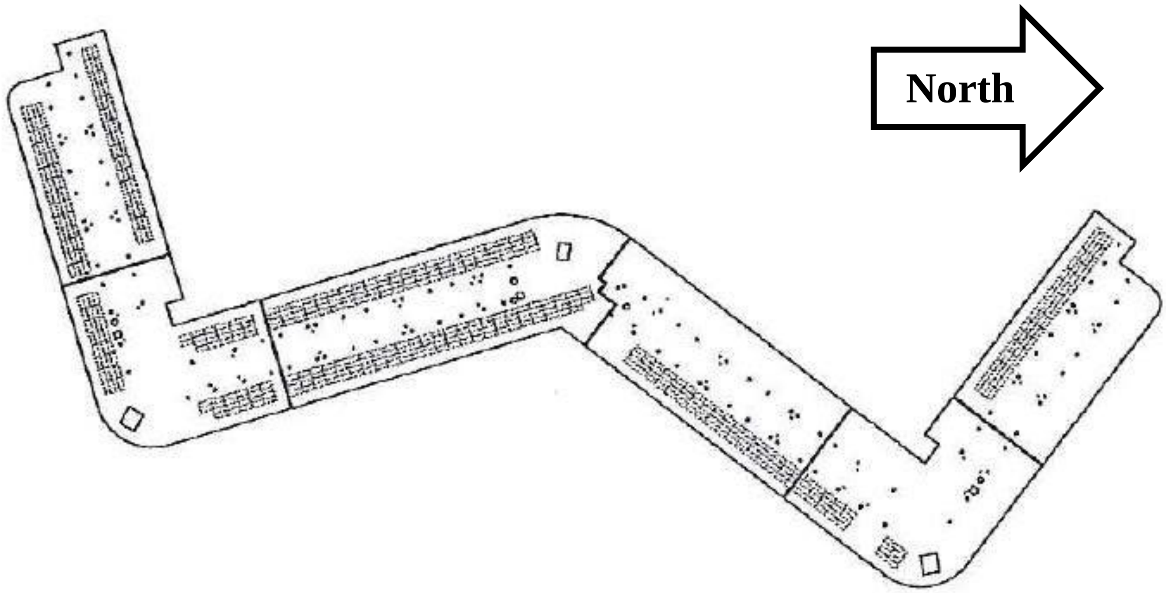

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Image: SPIRE Solar Systems, courtesy of PAG.

In a net-metered installation, the PV+BES system would be connected behind the “house” meter. To form a microgrid, the installation would need an appropriate inverter, controls, switchgear, protective relays and other equipment to provide power to the facility critical loads. In contrast, PV installations that are compensated by the more economically advantageous REG FIT are connected directly to the grid distribution network with a dedicated meter that measures energy production as the basis for owner compensation. To form a microgrid in “island mode”, controls and switchgear would be required to disconnect the PV+BES from the grid and connect it to the facility critical loads circuit. To the authors’ knowledge, this design has not been attempted in a PV installation funded by the REG FIT. For the purposes of this analysis we assumed that this configuration would be allowable, although that has yet to be determined in practice.

Combined heat and power. The facility has natural gas supply, facilitating consideration of a small-scale CHP system. CHP can provide constant power and thermal energy as long as there is natural gas supply. A 35 kW reciprocating engine module fueled by natural gas was selected for analysis, sized according to site characteristics, monthly utility usage data, and estimated thermal and electrical loads; metered interval data was not available.

During grid outages that require back up power, microgrid controls and switches could enable the CHP system to operate in grid-independent “island mode” and power the critical loads circuit. This model is a synchronous generator that can operate in island mode without a reference power frequency signal provided by the grid. This capability contributes to EDC concerns about the risk of potential back feeding power to the grid or unintentional islanding, so the system would require protective relays and other measures to be approved for utility interconnection to operate in island mode, adding significant cost and complexity. The 35 kW CHP module's capacity is insufficient to serve the estimated critical loads. It would be need to be controlled to operate in tandem with the BUG and/or PV+BES as a "hybrid" system, *e.g.*, with the CHP module operating at full output and the BUG varying its output as necessary to serve the remainder of the load; other SOO strategies are possible. This also would significantly increase controls complexity and cost. (Note that CHP manufacturer Tecogen is developing an inverter system capable of integrating their 100 kW CHP module with a PV or PV+BES system for tandem operations; this system should be available in 1–2 years.[259])

National Grid offers significant financial incentives for CHP on a per-kW basis (*e.g.*, $1000/kW), but currently there are no programs in Rhode Island that provide financial support for CHP energy production (*e.g.*, RECs or thermal energy credits). CHP is not eligible for RI's net metering program.

Complicating factors hinder the CHP option in this case. BCV has two mechanical rooms that each heat half of the building, reducing the ability to make use of CHP byproduct heat to serve the site's full thermal load from a single location. The unit would be installed inside the North mechanical room where it could provide byproduct heat for both HHW for half of the building and DHW for the whole building. Configuring this synchronous generator to be approved for utility interconnection and operate in island mode entails significant cost and complexity. Under normal grid-connected conditions it would not run all the time for economic reasons. High initial cost, small system size and limited run-hours reduce the annual cost savings and prolong the payback period. The CHP module is relatively quiet, but would require an external dump radiator to discard excess thermal energy under certain operating conditions. Dump radiators include fans and they can be noisy, which could be a source of concern among the residents.

2.3. HOMER Analysis

Inputs

Solar resource data and weather information for Westerly, RI were downloaded using HOMER's location selection function. To build profiles for electrical and thermal loads, HOMER's default profiles for a residential use type were modified and scaled to match data taken from Babcock Village's utility bills.

[259] http://www.prnewswire.com/news-releases/tecogen-introduces-bold-new-inverter-technology-with-inv-100e-300209740.html

Figure BCV-4: Babcock Village Electrical Load

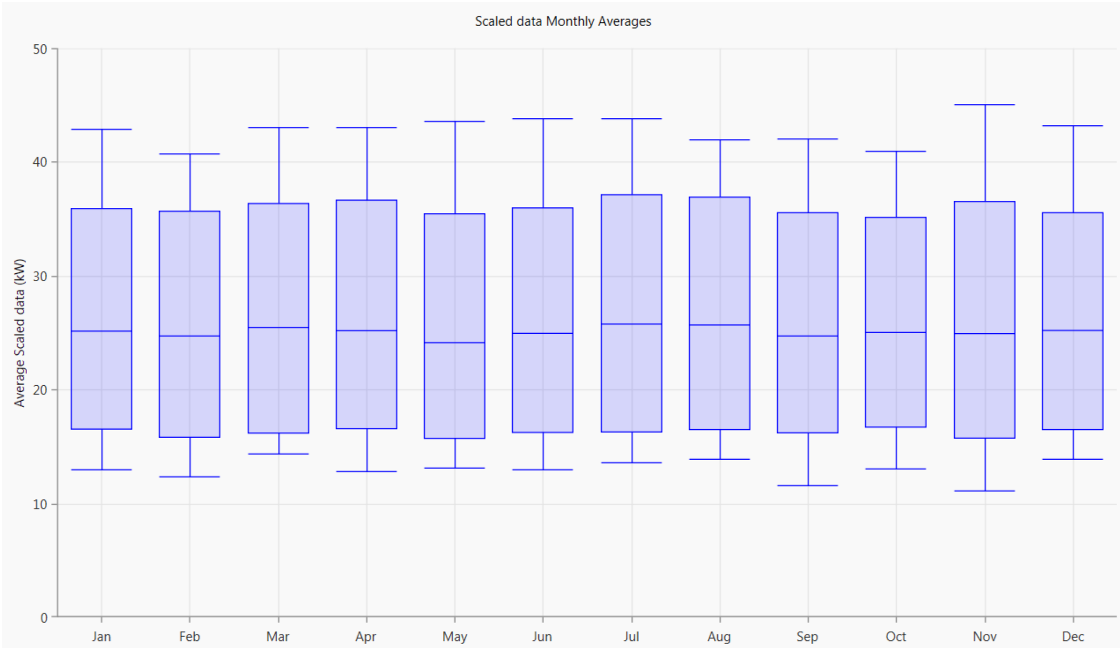


Image from HOMER Energy Software

Figure BCV-5: Babcock Village Thermal Load

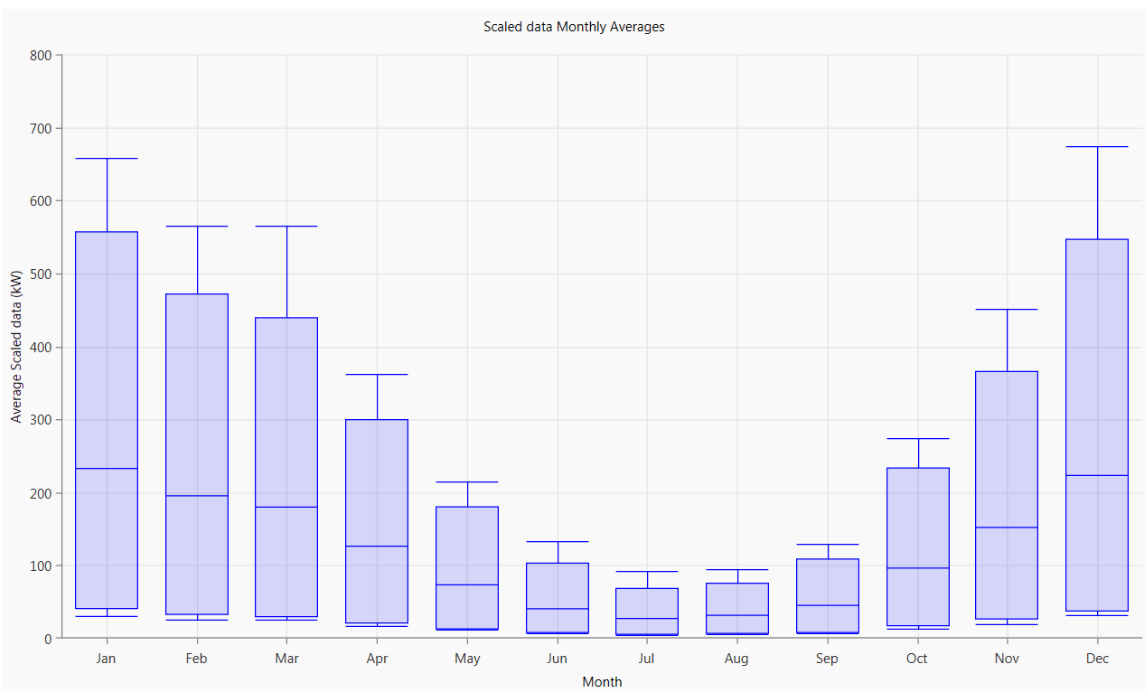


Image from HOMER Energy Software

Electricity prices were split into prices billed on a $/kWh basis (supply and delivery charges) and those billed on a $/kW basis (demand charges). Our analysis included National Grid's planned reductions in the supply charge by approximately $0.03 per kWh, to a future rate of $0.102/kWh. The demand charge of $7.90/kW and the reduced supply/distribution charge of $0.10/kWh were modeled in HOMER. For illustration, the blended rate (which excludes fixed customer charges) was approximately $0.13/kWh. A natural gas price of $0.41/therm was based on bills from National Grid.

Table BCV-1: Babcock Village Electrical Rates

Fixed	Demand	Supply	Delivery	Supply + Delivery	Reduced
$/mo	**$/kW-mo**	**$/kWh-mo**	**$/kWh-m**	**$/kWh-mo**	**$/kWh-mo**
$ 130	$ 7.902	$ 0.098	$ 0.034	$ 0.132	$ 0.102

<u>Solar power plus battery storage systems analysis</u>

Our analysis selected a PV system capacity of 155 kW due to factors described in section E2.2. We used HOMER software to model the installation under two PV procurement scenarios, one using the National Grid's REG program feed-in-tariff (FIT) of $0.225/kWh, and another using the net metering provision. Revenue from the production of electricity under net metering was modeled in two echelons: $0.102/kWh (reduced supply + distribution) up to 100% of the facility's consumption, and $0.07/kWh (reduced supply) up to 125% of the facility's consumption.

<u>Combined Heat and Power systems analysis</u>

A 35 kW CHP unit was used in this analysis. Assumptions for cost, production, and equipment lifetime were based on comparable systems. We included a representative operation and maintenance (O&M) contract that covers the full cost of unit operation, maintenance, and replacement at a price of $1.35/hour with a 5% annual escalation rate. This was modeled in addition to a self-performed O&M scheme. The remaining system components costs were taken from HOMER defaults and market research.

Table BCV-2: Babcock Village Cost Assumptions

Component	Installed Cost	Operating Cost
Solar PV	$2,500 / kW	$10 / kW / yr
Natural Gas CHP	$4,500 / kW	$2.58* / hour
Inverter	$252 / kW	-
Batteries	$534 / kWh	$10 / kW / yr

* $1.35 / running hour including 5% escalation averaged out over 25 years

<u>HOMER model</u>

HOMER analyzes different combinations of resources based on input parameters to determine the configuration with the lowest levelized cost of energy (LCOE). It includes a baseline scenario in which electricity is drawn from the grid, and heat from a natural gas-fired boiler. For each combination, HOMER performs an 8,760 hour annual analysis that optimizes generation, power purchased from the grid, and power sold to the grid. This analysis used a discount rate of 6%, and was 25 years in duration.

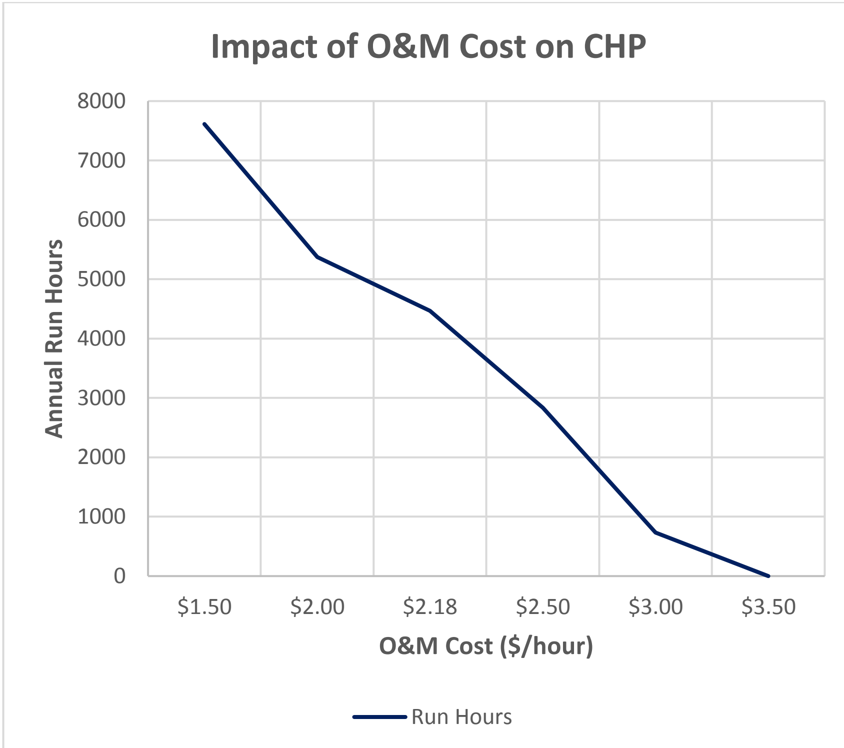
Configurations considered were baseline grid, solar plus storage, and CHP. The 155 kW solar array was modeled with and without the FIT. In the scenario without the FIT, excess generation is credited at the grid cost of electricity to approximate net metering. It was assumed that CHP is not eligible to sell electricity back to the grid.

Table BCV-3: Solar Scenarios Modeled

Solar Scenario	Compensation
1A Grid + Solar + Battery	Net Metering Only (No Feed-in-Tariff)
1B Grid + Solar + Battery	Feed-in-Tariff of $0.225/kWh

HOMER dispatches the CHP unit when its marginal cost of operation (including O&M cost, fuel cost, and future replacement cost or “wear and tear”) makes financial sense. Both this dispatch strategy and overall CHP economics were found to be highly sensitive to input O&M cost, lifetime hours, and the annual hours of operation. The high marginal cost in the O&M contract prevented the unit from being dispatched in HOMER’s optimization for BCV. To assess this scenario, a dispatch schedule was constructed by setting the replacement cost equal to zero and varying the O&M cost was between $3.50 per operating hour (at which point the unit would not run) and $1.50 per operating hour (at which point the unit would run nearly continuously).

Figure BCV-6: CHP O&M Cost Study



At about 4,015 annual operating hours, the CHP unit would operate only at an output at or above ~20 kW of its 35 kW maximum output. This gave a capacity factor of 38.9%, which was used as the dispatch schedule for the analysis. Two O&M costs were modeled: one using an O&M contract priced at $2.58/hour, and one using a HOMER default value of $0.03/kWh plus a replacement cost. In the contract scenario, replacement cost is assumed to be $0 (the contracted company would replace the unit). In the low O&M cost scenario, CHP units were assumed to be replaced by BCV/PAG. Unit lifetimes of 20,000 hours, 40,000 hours, and 60,000 hours were considered. This gave five, two, and one system replacements (assumed to be the whole CHP unit) over the analysis period, respectively. It is noted that this study was used to inform choice of dispatch schedule, but doesn't represent a real installation; some O&M contract would be needed to maintain the CHP unit.

Table BCV-4: Babcock Village CHP Scenarios Modeled

CHP Scenario	O&M Cost	Lifetime Hours	No. of Replacements Charged to Owner
2A Grid + CHP	$2.58/hour	20,000	0
2B Grid + CHP	$0.03/hour	20,000	5
2C Grid + CHP	$0.03/hour	40,000	2
2D Grid + CHP	$0.03/hour	60,000	1

Results and Analysis

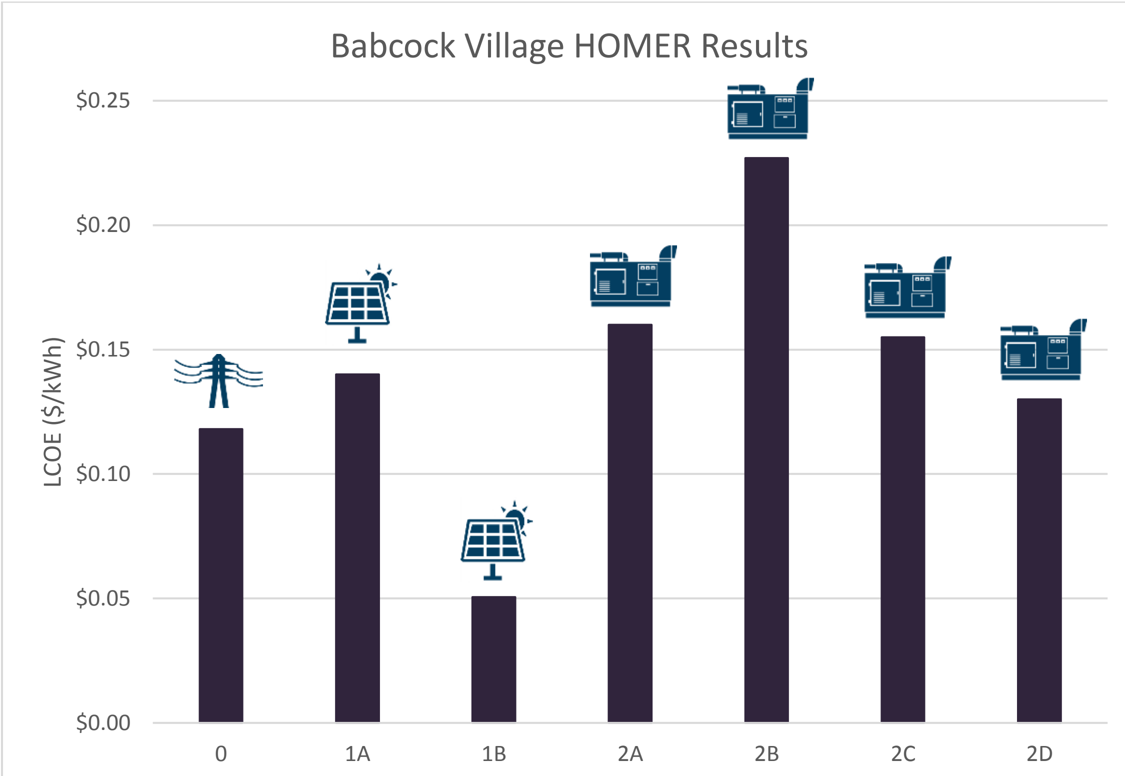
Table BCV-5: Babcock Village Scenario Overview

Scenario	Description
0	Grid
1A	Grid + Solar + Battery (without FIT)
1B	Grid + Solar + Battery (with FIT)
2A	Grid + CHP (Contract O&M)
2B	Grid + CHP (Low O&M, 20,000 hr life)
2C	Grid + CHP (Low O&M, 40,000 hr life)
2D	Grid + CHP (Low O&M, 60,000 hr life)

Table BCV-6: Babcock Village HOMER Modeling Results

Scenario	PV	Battery	CHP	LCOE	Net Present Cost	Initial Capital Cost	Annual Cost	Simple Payback
	kW	kWh	kW	$/kWh	$	$	$/yr	yrs
0	-	-	-	$0.12	$707,677	$0	$44,925	-
1A	155	31	-	$0.14	$926,822	$419,941	$32,178	32.9
1B	155	31	-	$0.05	$523,954	$419,941	$6,603	11.0
2A	-	-	35	$0.16	$840,535	$157,500	$43,361	100.7
2B	-	-	35	$0.23	$1.08M	$157,500	$58,863	No Payback
2C	-	-	35	$0.16	$835,178	$157,500	$43,021	82.7
2D	-	-	35	$0.13	$749,252	$157,500	$37,566	21.4

Figure BCV-7: Babcock Village Scenario LCOE



Scenario 1B solar plus storage with the FIT is by far the best option on a LCOE basis, with a LCOE of only $0.05/kWh. This is due to the fact that the FIT value of $0.225/kWh is much higher than the grid cost of electricity, and the system is able to export significant quantities of electricity at this rate. All other scenarios exceed the baseline grid LCOE of $0.12/kWh. Scenario 1A solar plus storage without the FIT is still competitive at $0.14/kWh.

The high O&M cost associated with a maintenance contract drives Scenario 2A's LCOE up to $0.16/kWh. The LCOE varies between $0.13/kWh and $0.23/kWh for the three low O&M cost scenarios, exhibiting a strong dependence of the LCOE on lifetime hours. Based on expected lifetime hours, a CHP at this scale is likely to fall on the higher end of this range. Because CHP is ineligible to sell electricity back to the grid, it must be sized for the facility's baseload. This small sizing may make the unit relatively more expensive. Eligibility for net metering would improve CHP economics.

Reductions in demand charges are modeled in HOMER, but cannot be considered highly probable. This is due to PV+BES intermittent output and CHP system's low capacity factor (*i.e.*, it doesn't run all the time) and uncertain availability factor (*i.e.*, it might not be operating at any given time). These factors reduce the probability that DER output will coincide with unpredictable 15 minute periods of peak facility demand that determine demand charges. A much larger battery storage bank would be needed, or the CHP unit would need to operate 100% of the time, to provide demand charge reductions with high reliability; neither is feasible. Demand charge reductions are not included in the primary CBAM analysis, but the sensitivity of results to their inclusion is explored.

CBAM

Information used in the CBAM was identical to that used in the HOMER analysis, with a few exceptions. The cost of electrical infrastructure was included, and the size (and cost) of the battery storage system was increased to provide electricity for four hours at the facility's peak load. Table E-2 shows the assumed costs for these components. The O&M cost used for CHP is adjusted downwards from $2.58/hour to $2.10/hour. The $2.58/hour rate comes from a contract clause using a 5% escalation rate, which includes a rate of inflation. Because the CBAM makes use of base year dollars, that inflation assumption is removed using the average inflation rate for the Consumer Price Index over the last ten years, equal to 1.75%.[260] The remaining 3.25% escalation applied to the O&M contract cost of $1.35/hour gives an average annual O&M cost over the analysis period of $2.10/hour. The cost of electrical infrastructure was estimated to be $22,600.

Table BCV-7: Babcock Village CBAM Scenarios

	Solar	**CHP**	**Batteries**	**Inverter**
	kW	kW	kWh	kW
1. Solar	155	-	172	63
2. CHP	-	35	-	-
3. Both	155	35	172	63

The following figures show the inputs and outputs used for the scenario with both solar PV and CHP at Babcock Village. For scenarios with only one or the other, the appropriate inputs are later deleted.

[260] http://www.inflation.eu/inflation-rates/united-states/historic-inflation/cpi-inflation-united-states.aspx

Figure BCV-8: Babcock Village Model Parameter Inputs

Model Inputs				**Color Key**
Analysis start year	2020			Inputs
Analysis end year	2045			Outputs
Analysis Period	25	Years		Benefits
Discount rate	6%	%		Costs
				Calculations
EIA Price Forecast: Choose scenario	No Energy Price Forecast			Reference Data
EIA Price Forecast: Choose sector	Residential			
Input Desired Grant Funding		$		
Desired Payback		years		
Output Funding Needed		$		

Figure BCV-9: Babcock Village Financial Outputs and Benefits for Solar PV and CHP Scenario

Key Outputs

Financials		
Benefit-Cost Ratio	1.0009	
Simple Payback	13	years
Internal Rate of Return (IRR)	6%	%
Return on Investment (ROI)	4%	%
Project LCOE (electricity only)	$ (0.079)	$/kWh
Project LCOE (with thermal gen.)	$ (0.048)	$/kWh

Microgrid Benefits		
Category	**Present Value**	**Annualized Value**
Avoided Boiler Fuel Purchases	$ 50,542.74	$ 3,953.79
Electricity Sales Revenue	$ 810,532.32	$ 63,405.28
Energy Efficiency Savings	$ -	$ -
Additional Benefits	$ -	$ -
Year 1 Grant	$ -	$ -
Salvage Value	$ -	$ -
TOTAL MG BENEFITS	$ 861,075.07	$ 67,359.08

Figure BCV-10: Babcock Village Costs and Energy Outputs for Solar PV and CHP Scenario

Microgrid Costs		
Category	**Present Value**	**Annualized Value**
Design Costs	$ -	$ -
Capital Investments	$ (675,324.00)	$ (52,828.38)
Non-Fuel Fixed O & M	$ (161,468.14)	$ (12,631.12)
Non-Fuel Variable O & M	$ -	$ -
MG Fuel Cost for CHP and Generation	$ (74,057.94)	$ (5,793.31)
MG Boiler Fuel Cost	$ (207,228.60)	$ (16,210.81)
MG Electricity Purchases	$ (387,896.21)	$ (30,343.85)
Energy Efficiency Costs	$ -	$ -
Additional Costs	$ -	$ -
TOTAL MG COSTS	$ (1,505,974.89)	$ (117,807.47)

Baseline Costs		
Category	**Present Value**	**Annualized Value**
Baseline Electricity Purchases	$ (387,896.21)	$ (30,343.85)
Baseline Thermal Fuel Purchases	$ (257,771.35)	$ (20,164.61)
TOTAL BASELINE COSTS	$ (645,667.55)	$ (50,508.45)

MG Benefits - Costs		
Category	**Present Value**	**Annualized Value**
MG Net Present Cost	$ (644,899.82)	$ (50,448.40)
MG Net Present Cost Relative to Baseline	$ 767.73	$ 60.06

Energy		
Baseline Electricity Consumption	220,137	kWh/year
Reduced Electricity Consumption	220,137	kWh/year
Baseline Electricity Demand	46	Peak kW
Reduced Electricity Demand	46	Peak kW
Electricity Generated	326,483	kWh/year
Electricity Purchased	-	kWh/year
Excess Electricity	106,346	kWh/year
Baseline Thermal Load	3,581	MMBtu/year
Reduced Thermal Load	3,581	MMBtu/year
CHP Thermal Generation	702	MMBtu/year
Boiler Thermal Generation	2,879	MMBtu/year

Figure BCV-11: Babcock Village Cash Flow Diagrams for Solar PV and CHP Scenario

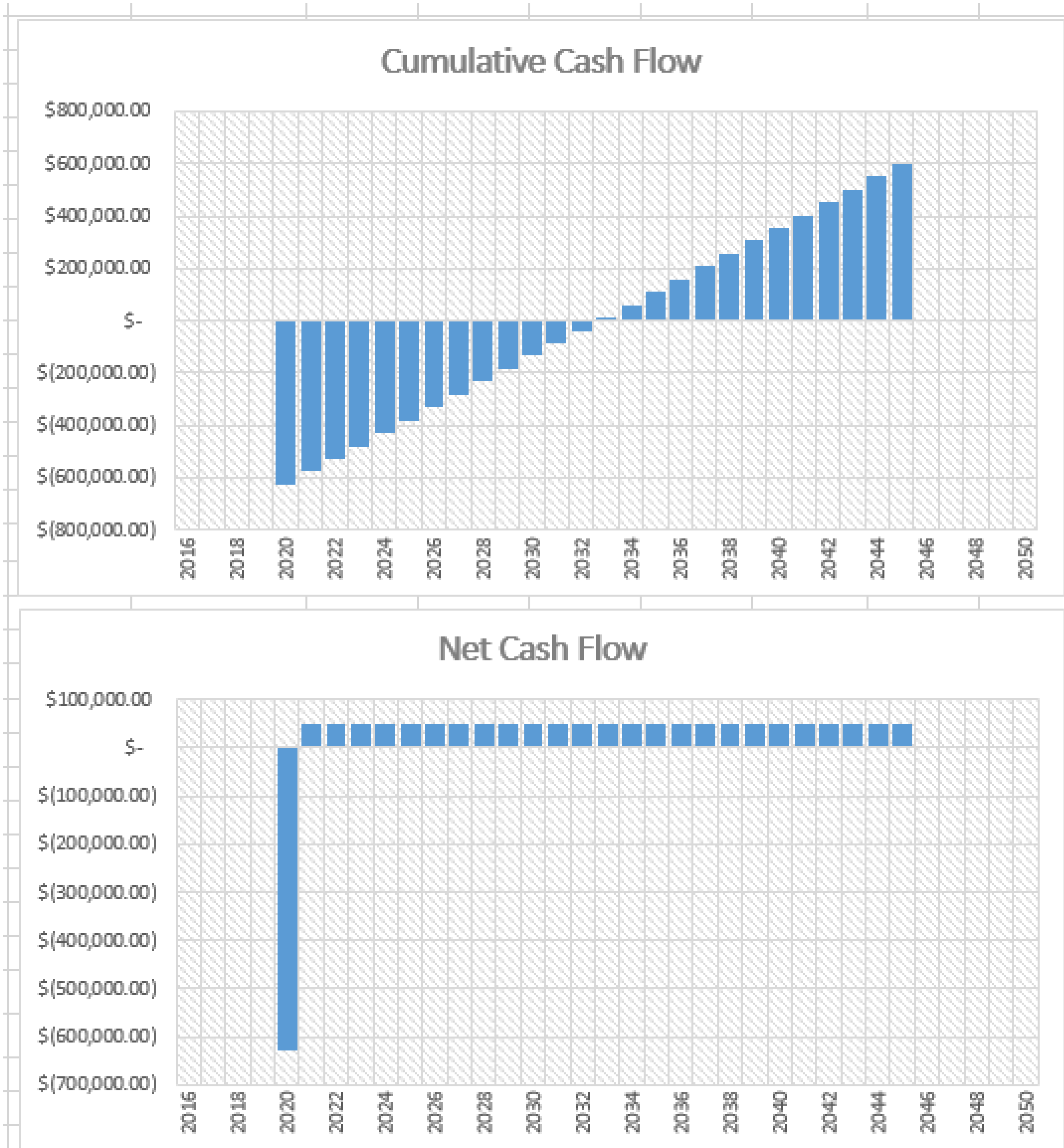


Figure BCV-12: Babcock Village Electric and Thermal Loads for Solar PV and CHP Scenario

	Electricity Consumption													
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM	YEAR AVE
Facility	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
Babcock Village	20864	19603	20231	18465	17436	15661	17948	18155	17357	17452	17965	19001	220137	18345
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
SUM	20864	19603	20231	18465	17436	15661	17948	18155	17357	17452	17965	19001	220137	18345

	Electricity Demand												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM
Facility	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW
Babcock Village	44	38	40	45	42	44	45	43	46	43	45	45	519
													0
													0
													0
													0
													0
													0
													0
													0
													0
SUM	44	38	40	45	42	44	45	43	46	43	45	45	

Figure BCV-13: Babcock Village Electricity Rate Inputs for Solar PV and CHP Scenario

Thermal Fuel Purchases																	
	Fuel Type	Fuel Cost	Boiler / Furnace Name	Boiler / Furnace Efficiency	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM
Facility		$/MMBtu		%	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu
Babcock Village	Natural Gas	4.1	Boiler I	79%	763	642	575	403	231	122	80	86	136	306	490	725	669
																	0
																	0
																	0
																	0
																	0
																	0
																	0
																	0
																	0
SUM					763	642	575	403	231	122	80	86	136	306	490	725	4561

UTILITY ELECTRICITY RATES			
	Fixed Charges	Energy Charges	Demand Charges
Facility	$/month	$/kWh-mo.	$/kW-mo.
Babcock Village	$ 132.40	$ 0.10	$ 7.90
SUM			

REFERENCE HEATING UNIT CONVERTER			
	MMBtu	0.00	Btu
		0.0000	MMBtu
		0.00	kWh
		0.00	Therm
		0.00	Ccf Natural Gas

Figure BCV-14: Babcock Village CHP and Electrical Generation for Solar PV and CHP Scenario

GENERATING ASSETS

Electricity Generating Resources

Resource	Rated Power kW	Fuel Type	Fuel Consumption MMBtu/kWh	Fuel Cost $/MMBtu	Compensated for Overgeneration?
Solar I	155		0	$ -	Yes
SUM	155				

Combined Heat & Power Resources

Resource	Rated Power kW	Fuel Type	Fuel Consumption MMBtu/kWh	Fuel Cost $/MMBtu	Compensated for Overgeneration?	Maximum Thermal MMBtu/hr	Associated Facility:	Offset Fuel From:
CHP I	35	Natural Gas	0.011	$ 4.10	Yes	0.2463	Babcock Village	Boiler I
SUM	35							

Figure BCV-15: Babcock Village Electrical and Thermal Generation Inputs for Solar PV and CHP Scenario

ELECTRICAL GENERATION

	Electricity Generation												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM
Resource	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	
Solar I	14228	15449	20455	18935	19995	19007	18962	19151	18352	17102	12865	12845	207348
CHP I	10119	9100	10260	9837	9818	9744	10289	10281	9771	10047	9743	10128	119135
													0
													0
													0
													0
													0
													0
													0
													0
SUM	24347	24550	30715	28772	29813	28751	29250	29432	28122	27149	22608	22972	326483

THERMAL GENERATION

	CHP Thermal Generation												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM
Resource	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	
CHP I	59.6	53.6	60.5	58.0	57.9	57.4	60.6	60.6	57.6	59.2	57.4	59.7	702.084917
													0
													0
													0
													0
													0
													0
													0
													0
													0
SUM	59.63091863	53.62991972	60.46376733	57.97038389	57.85866945	57.42475325	60.63257104	60.58587061	57.5794048	59.20807481	57.41715626	59.68342718	702.084917

Figure BCV-16: Babcock Village Efficiency Inputs [*None Entered*]

ENERGY EFFICIENCY							
ENERGY EFFICIENCY UPGRADES							
Facility	Reduction of Energy Demand	Reduction of Energy Usage	Reduction of Heating Demand	Offset Fuel From:	Efficiency Capital Cost	Efficiency O&M Cost	Description of ECM Package
	kW/month	kWh/month	MMBtu/month		$	$/Year	
SUM	0	0	0		$ -	$ -	

Figure BCV-17: Babcock Village Capital and Fixed O&M Cost Inputs for Solar PV and CHP Scenario

MICROGRID COSTS

CAPITAL COSTS			
Component	Installed Cost	Year of Purchase	Lifetime
	$		Years
Solar I	$ 387,500.00	2020	25
Batteries	$ 91,848.00	2020	25
CHP I	$ 157,500.00	2020	25
Inverter	$ 15,876.00	2020	25
Electrical Hardware	$ 22,600.00	2020	25
SUM	$ 675,324.00		

FIXED NON-FUEL O & M COSTS			
Component	Cost	Start Year	End Year
	$		
Solar I	$ 1,550.00	2020	2045
Batteries	$ 1,720.00	2020	2045
CHP I	$ 8,444.72	2020	2045
SUM	$ 11,714.72		

Figure BCV-18: Babcock Village Variable Cost Inputs [*None Entered*]

VARIABLE NON-FUEL O & M COSTS: MANUAL INPUT		
Component	**Cost**	**Year**
	$	
SUM	$ -	

VARIABLE NON-FUEL O&M: $/kWh INPUT	
Component	**Cost**
	$/kWh
SUM	0

VARIABLE NON-FUEL O&M: $/MMBtu INPUT	
Component	**Cost**
	$/MMBtu
SUM	0

Figure BCV-19: Babcock Village Additional Cost Inputs [*None Entered*]

ADDITIONAL ONE-TIME COSTS			
Component	Cost	Year	Description
SUM	$ -		

DESIGN COSTS	
Component	Cost
	$

ADDITIONAL ONGOING COSTS				
Component	Cost	Start Year	End Year	Description
SUM	$ -			

Figure BCV-20: Babcock Village Benefits Inputs for Solar PV and CHP Scenario

MICROGRID BENEFITS

COMPENSATION FOR OVERGENERATI		Option 1: Not Behind the Meter		Option 2: Behind the Meter						
Generating Resource	Revenue Model	Fixed Payments	Energy Payments	Associated Facility	Price Tier 1: Max % Load	Fixed Payments	Energy Payments	Price Tier 2: Max % Load	Fixed payments	Energy Payments
		$/month	$/kWh		%	$/month	$/kWh	%	$/month	$/kWh
Solar I	Not behind the met	$ -	$ 0.23	Babcock Village	100%	$ -	$ 0.10	125%	$ -	$ 0.07
CHP I	Behind the meter	$ -	$ -	Babcock Village	100%	$ -	$ 0.10		$ -	$ -
SUM		$ -	$ 0.23							

ADDITIONAL ONE-TIME BENEFITS			
Component	Benefit	Year	Description
SUM	0		

ADDITIONAL YEARLY BENEFITS				
Component	Benefit	Start Year	End Year	Description
SUM	0			

Conclusions and recommendations

A CBAM tool was used to explore the effect upon project economics of a number of different policy decisions.

The tool was used to analyze three different scenarios: solar PV (scenario 1), CHP (scenario 2), and both PV and CHP (scenario 3). Scenario 3 is used for illustration; in actuality, CHP electricity production would reduce Babcock Village's electrical demand. This in turn would reduce the size of solar array eligible for payment under net metering or a FIT. These scenarios assume a FIT; sensitivity to this assumption is later analyzed. Results are shown in Table BCV-8. The solar scenario has an 11 year payback, and the scenario with both solar and CHP has a payback of 13 years. The CHP scenario does not pay back during the 25-year analysis period; as in the HOMER analysis, the high cost of an O&M contract plus fuel cost makes the CHP unit expensive to operate. The internal rates of return for the scenarios including solar are small, but positive.

Table BCV-8: CBAM Results – No Grant Support

	Benefit-Cost Ratio	Simple Payback	IRR	ROI	LCOE	LCOE (Electrical and Thermal Gen.)
		years	%	%	$/kWh	$/kWh
1. Solar	1.14	11	8%	5%	$0.11	$0.11
2. CHP	0.68	No Payback in Analysis Period	-2%	-1%	$0.25	$0.09
3. Both	1.00	13	6%	4%	$0.08	$0.05

The levelized cost of energy (LCOE) in the CBAM uses the total cost of supplying Babcock Village's energy needs. In Table BCV-8, the fifth column entitled "LCOE" divides that cost by the electricity produced only, while the sixth column entitled "LCOE (Electrical and Thermal Gen.)" divides the total cost by electric and thermal energy produced.

The LCOE appears to be higher than that shown in HOMER for both solar and CHP. This can be attributed to the inclusion of electrical infrastructure costs and a larger battery array. The additional battery array costs are necessary to achieve resilience objectives. The electrical infrastructure is included to more accurately depict actual project costs.

One of the features in the CBAM is the option to include price escalation. This does not include inflation; it represents the expectation that the real value of electricity and fuel will change in the future. This has a small, but noticeable effect on the results. Table BCV-9 shows results using the "No Clean Power Plan" price escalation scenario from the U.S. Energy Information Administration (EIA). All scenarios become more attractive.

Table BCV-9: CBAM Results – No Grant Support, "No Clean Power Plan" Price Escalation

	Benefit-Cost Ratio	Simple Payback	IRR	ROI	LCOE	LCOE (Electrical and Thermal Gen.)
		years	%	%	$/kWh	$/kWh
1. Solar	1.34	10	10%	7%	$0.11	$0.11
2. CHP	0.78	22	2%	1%	$0.27	$0.10
3. Both	1.16	11	8%	6%	$0.07	$0.04

The first policy that can be analyzed is the provision of grant funding in the amount needed to reach a 15 year payback. Results are shown in Table BCV-10.

Table BCV-10: CBAM Results – Grant Support for 15-Year Payback

	Grant Amount	Benefit-Cost Ratio	Simple Payback	IRR
	$		years	%
1. Solar	$0.00	1.14	11	8%
2. CHP	$90,000.00	0.96	15	4%
3. Both	$0.00	1.00	13	6%

The first column shows the grants required. Scenarios 1 and 3 do not need grants; they already have payback periods of 11 and 13 years, respectively. Grant funding needed for scenario 2 is $90,000. The cash flow for scenario 2 is positive, but smaller, which is why it requires a larger grant. This is due to the high cost of an O&M contract, and the small thermal load at BCV. It is also worth noting that allowing CHP to receive payments for exporting excess electricity production to the grid would change the economics for a bigger unit. CBAM can be used to explore the impact of such a policy.

The next policy that could be implemented is one in which grant funding is provided to cover the installed cost of everything except the solar panels or CHP unit. The results of this policy are shown in Table BCV-11.

Table BCV-11: CBAM Results – Grant Support for Electrical Infrastructure and Batteries

	Grant Amount	Benefit-Cost Ratio	Simple Payback	IRR
	$		years	%
1. Solar	$130,324.00	1.37	8	12%
2. CHP	$22,600.00	0.75	No Payback in Analysis Period	-1%
3. Both	$130,324.00	1.15	11	9%

The grants for scenarios 1 and 3 are greater in value than the grant from scenario 2 because they include the battery and inverter costs of the solar array. Because of the smaller grant amount, CHP does not pay back during the analysis period. This funding strategy brings the payback for scenario 1 from 11 years to 8 years. The payback period for scenario 3 is shortened to 11 years from 13.

The assumptions fed into the CBAM have a direct effect on the results shown; a number of these will now be explored. The choice of FIT or net metering as the means by which solar electricity production is compensated has a big impact on solar economics, as shown in Table BCV-12. The first two rows show solar with and without the FIT, absent any grant funding. The third row shows the grant funding that would be needed to bring a scenario 1 to a 15 year payback without a FIT; the required amount is $186,000. With a FIT, solar doesn't need a grant; solar economics are highly sensitive to this assumption.

Table BCV-12: CBAM Results – Comparison of FIT and Net Metering

	FIT	Grant Amount	Benefit-Cost Ratio	Simple Payback	IRR	LCOE
	Y/N	$		years	%	$/kWh
1. Solar	Y	$0.00	1.14	11	8%	$0.11
	N	$0.00	0.60	23	1%	$0.19
	N	$186,000.00	0.93	15	5%	$0.15

In the above analysis, the conservative assumption is made that savings from demand charge reductions is $0. However, it is useful to explore the impact on project economics of relaxing that assumption- particularly for the CHP unit. Using the "Additional Yearly Benefits" box on the "Design Inputs" tab of CBAM, an estimated $1,984 annual demand charge savings are entered. This value is calculated as the difference between baseline demand charges and the demand charges calculated in HOMER. Including this source of savings has a positive impact on the CHP scenario, shown in Table BCV-13. The first, second, and third rows show no grant funding,

funding needed for a 15 year payback, and electrical infrastructure grant funding, respectively. The grant needed to achieve a 15 year payback drops to $58,000 from $90,000.

Table BCV-13: CHP Results with Demand Charge Reductions

	Grant Amount	Benefit-Cost Ratio	Simple Payback	IRR
	$		years	%
2. CHP	$0.00	0.77	23	1%
	$58,000.00	0.95	15	4%
	$22,600.00	0.84	20	2%

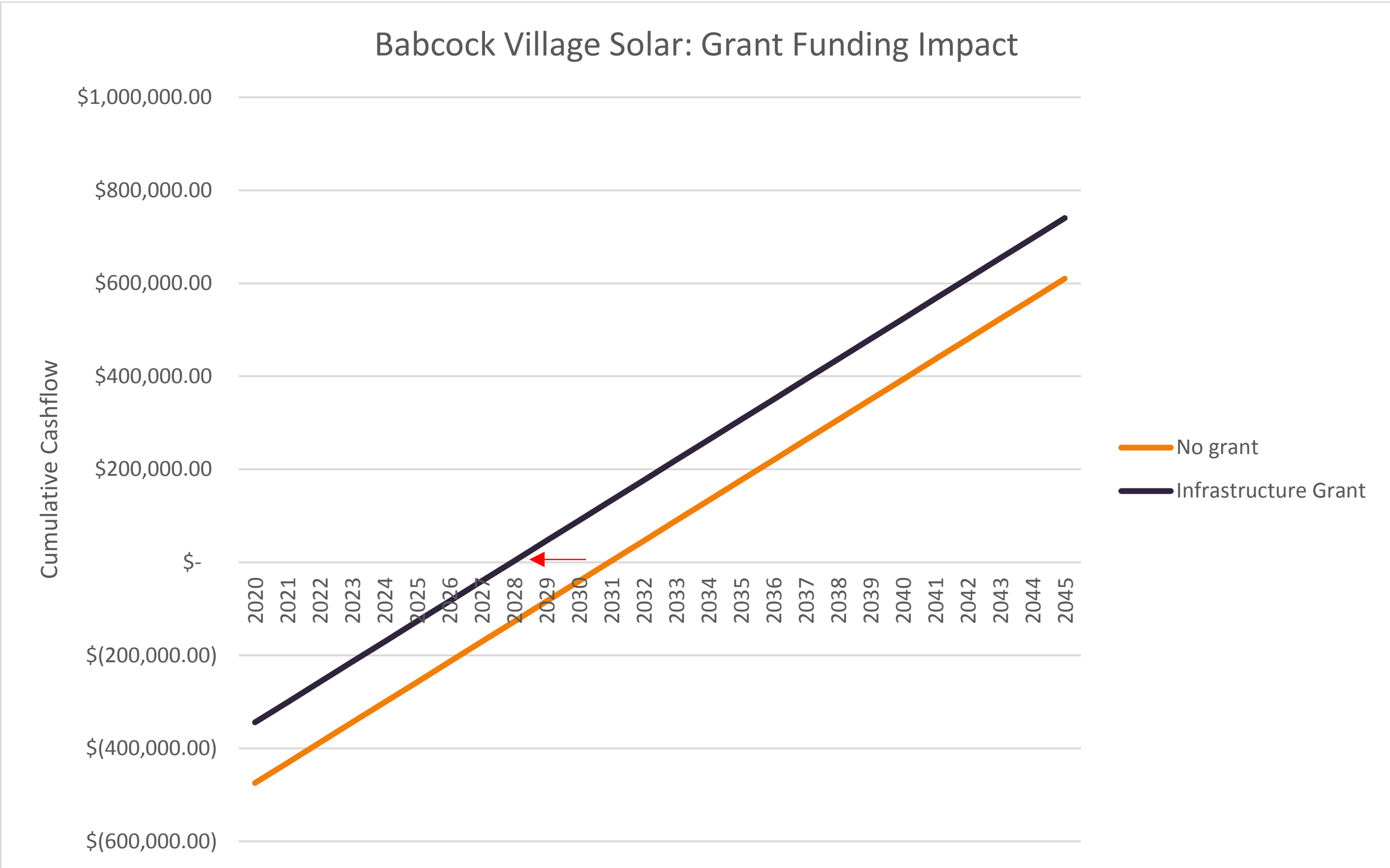
Assuming eligibility for a FIT, solar plus storage is recommended as a resilient backup power system for Babcock Village. The facility's large roof allows a sizable system to be installed. Coupled with battery storage, this provides the desired backup power supply. Grant funding that covers only the batteries, inverter, and other electrical infrastructure results in an 8 year payback. Without any grant funding, the solar plus storage system will pay back in 11 years. If it is assumed that the solar array is not eligible for a FIT, a CHP system shows stronger economics.

As demonstrated, the results of this analysis are strongly dependent upon assumptions including the FIT, demand charge savings, the O&M cost, and unit lifetime, among others. As inputs become more detailed, the relative attractiveness of solar and CHP may shift.

Although a CHP system capable of grid-independent operation is not shown to be a highly attractive option in this case, this indication should not be taken to apply to every situation. Facilities with larger or more constant thermal loads would present more conducive conditions. The additional equipment required to make a CHP system capable of grid-independent operations adds significant cost and extends the payback period. If we assume that demand charge reductions were greater, the economics would be more favorable. For example, one CHP system manufacturer we interviewed reported that operational data on hundreds of installed systems in the 30–100 kW size range suggest that we could apply an assumed average of 9 months' worth of demand savings at 75% system output, which could reduce the payback period in this case to a 6–7 year range. Strong policy support and incentives can have significant effects on CHP deployment; see section D2.4 for further discussion.

Figure BCV-21 graphically illustrates the effect of the infrastructure grant on solar plus storage economics. The $130,324 grant shifts the payback from 11 to 8 years, shown with a red arrow.

Figure BCV-21: Grant Impact on Cumulative Cash Flow



Oxford Place case study

Please note that this section repeats some text from Section E2 to better serve as a stand-alone case. OXP's existing conditions are site-specific although it shares features and considerations with BCV. OXP's conceptual design section E3.2 differs from BCV's section E2.2 primarily in PV sizing factors and CHP module sizing, type and configuration. Section E3.3 HOMER analysis is site-specific.

3.1. Existing conditions

Overview: Oxford Place (OXP), is a low to moderate income (LMI) elderly multifamily housing (MFH) building located at 200 Gordon Ave, Providence, RI. At the time of this writing it is being purchased and renovated by Preservation Of Affordable Housing (POAH). This facility has 78 units of elderly housing. The site is in an area of minimum flood hazard. The "Reverse L"-shaped six-story structure was built in 1978. See Figure OXP-1.

Figure OXP-1: Oxford Place and Oxford Gardens, north at top.

(Note: The building labeled "Oxford Gardens" is actually OXP; all other buildings on the block are OXG.)

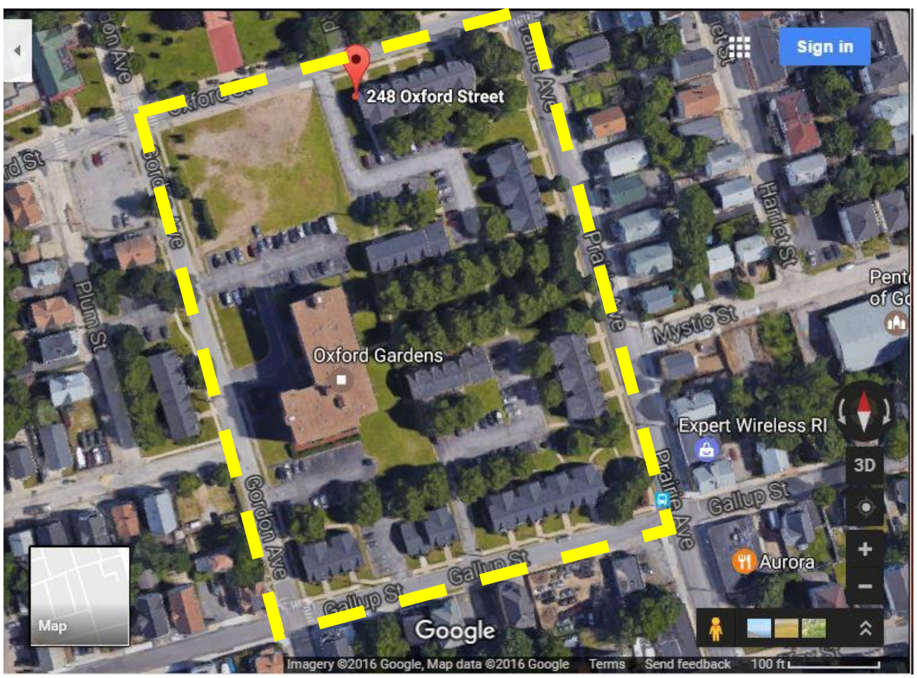


Image adapted from Google Maps.

The rest of the buildings on this city block (outlined in yellow in Figure OXP-1 above) comprise 44 residential units of single-story LMI MFH in single story structures also owned by the same organization, collectively called "Oxford Gardens" (OXG). Across Gordon Avenue due west of OXP is another 6 units of OXG housing. OXG units are individually-metered. Although this pilot project is focused on OXP, in the future there could be a potential Level 2 campus microgrid serving this entire city block of buildings with a single owner.

The OXP flat roof is being renovated with a new ballasted membrane system. The roof comprises 8" hollow core, tapered lightweight concrete planks. Minimal structural information is available for this system, so our analysis uses assumptions about load-bearing capacity in lieu of a resource-intensive investigation by a structural engineer that is beyond the scope of this report. The roof hosts an HVAC rooftop unit (RTU), a small elevator mechanical penthouse, a stairway structure, exhaust ventilators and television antennae which somewhat limit the amount of space available for rooftop PV.

Mechanical and electrical systems: There is one electricity master meter. The mechanical room, electrical room and generator room are adjacent to each other on the ground floor at to the electricity and natural gas service entrance, facing Gordon Ave. Natural gas supplies both the sealed-combustion boiler for heating hot water (HHW) that is circulated to baseboard heating in the building by a 7.5 HP pump, and the domestic hot water (DHW) boiler with a 7.5 HP circulation pump. There is no central cooling; numerous residents have installed window-mounted air conditioning units. The building has two elevators, each driven by a 25 HP motor. In recent years hallway lighting was upgraded, apartments were provided with Energy Star appliances and new water-efficient fixtures and toilets, and the roof was upgraded to R-25 insulation.

Backup power and critical loads: The building is served by a 150 kW diesel fueled backup generator (BUG) that is being replaced with a larger 200 to 250 kW unit in an external enclosure adjacent to the electricity service entrance. The BUG powers a critical loads circuit that includes life safety and fire protection systems (*e.g.*, 40 HP fire pump), boilers, hallway lighting, both elevators, site management office, and two community rooms with lighting, plug loads, a kitchenette area and each new split-system air-source heat pumps. Because the BUG does not power the apartments, the community rooms are used for shelter in place (SIP) operations and provide a safe haven with heating, cooling, device charging and food preparation and distribution, as occurred during the blackout caused by Hurricane Irene in 2011. After the renovation the critical circuit's total connected load on the new generator will be about 172 kVa / 147 kW.

3.2. Microgrid conceptual design

The facility already has a critical loads circuit connected to a diesel-fueled BUG. The microgrid conceptual design was to install additional clean(er)-energy DERs with controls, switchgear, protective safety measures and other equipment needed to disconnect from the grid and form a Level 1 single-facility, single-meter microgrid. The DERs could provide economic and environmental benefits during normal "blue sky" operations in grid-connected mode, as well as provide energy to the facility's critical loads while disconnected from the grid in "island" mode. No modifications to the facility's existing critical loads circuit were planned other than configuring the DERs to supply that circuit.

In island mode the retrofit DERs would be dispatched first to serve the critical loads, with the BUG shut down and standing by to provide backup power and "black start" capability to the DERs if required. Duration of DER operation would depend upon both the critical load profile and DER energy supply or storage capacity. When DERs could no longer serve the critical loads, the BUG would be dispatched. This configuration could reduce BUG run time, conserve diesel fuel and reduce emissions. Each DER configuration and Sequence Of Operation (SOO) described below would require approval from local Authorities Having Jurisdiction (AHJ) such as the utility and the fire department. We assumed that the described approaches would be approved, for the purposes of this discussion.

The authors considered two types of DERs: solar photovoltaics plus battery energy storage (PV+BES), and small-scale combined heat and power (CHP) or cogeneration, discussed further below.

Solar power plus battery energy storage. We developed an estimate of potential rooftop PV capacity that could be retrofit onto the flat roof, with consideration of factors including roof age, type, estimated structural load-bearing capacity, obstructions, and shading considerations. The PV could be connected via a protective conduit to a ground-level external installation comprising inverters, controls, energy storage, DC and/or AC disconnects (which could be installed on the roof also), protective measures, and other balance of system equipment that could enable grid-independent operations. Battery type and chemistry were not specified.

Under normal "Blue Sky" operations, the PV+BES system could provide economic benefits to the facility by reducing energy costs, primarily due to PV production. The BES probably could not provide significant economic benefits on a daily basis in this case, *e.g.*, by discharging during peak load periods to reduce demand charges; its primary value would be energy assurance during outages. Electric meter interval data was not available to develop a daily load profile. We inferred from OXP's billed peak loads and the occupants' demographics that the load profile would be fairly level, without significant peaks in the morning or evening such as occur in multifamily housing (MFH) where a large percentage of the residents leave during the workday and return at night.

During grid outages that require back up power, microgrid controls and switches would enable the PV+BES system to operate in "island mode" and power the critical loads circuit. The PV+BES system would be dispatched first, with the BUG shut down and standing by. The PV system would charge the BES, and the BES would provide energy to the critical loads. The PV+BES system would lack the capacity to serve the critical loads 24/7; our design was sized to serve estimated peak critical loads for 4 hours. Duration of operation would depend upon PV output and BES capacity and level of charge. When PV+BES could no longer serve the critical loads, the BUG would be switched on. It could be possible to configure the BUG to charge the BES and then switch off until needed.[261]

PV procurement options include Rhode Island's net metering provisions and the Renewable Energy Growth (REG) program feed-in tariff (FIT). Both programs stipulate that onsite PV capacity cannot produce more electrical energy than the building uses on an annual basis. OXP has one master meter, so the design assumption of 100 kW PV system size was defined primarily by roof characteristics rather than by net metering or REG program requirements. In island mode PV+BES powers OXP's critical load circuit only, excluding the apartments.

[261] Similar design configurations and SOO are employed at Level 1 microgrids including the Scripps Ranch Recreation Center in San Diego, CA and Fire Department Headquarters in Northampton, MA.

In a net-metered installation, the PV+BES system would be connected behind the facility meter. To form a microgrid, the installation needs an appropriate inverter, controls, switchgear, protective relays and other equipment to provide power to the facility critical loads. In contrast, PV installations that are compensated by the more economically advantageous REG FIT are connected directly to the grid distribution network with a dedicated meter that measures energy production as the basis for owner compensation. To form a microgrid in "island mode", controls and switchgear would be required to disconnect from the grid and connect to the facility critical loads circuit. To the authors' knowledge, this design has not been attempted in a PV installation funded by the REG FIT. For the purposes of this analysis we assumed that this configuration would be allowable, although that has yet to be determined in practice.

Combined heat and power. The facility has natural gas supply, facilitating consideration of a small-scale CHP system. CHP can provide constant power and thermal energy as long as there is natural gas supply. A 100 kW reciprocating engine module fueled by natural gas was selected for analysis, sized according to site characteristics, monthly utility usage data, and estimated thermal and electrical loads; metered interval data was not available. It could be located inside the mechanical room or externally adjacent, to facilitate byproduct heat utilization for HHW and DHW.

During grid outages that require back up power, microgrid controls and switches could enable the CHP system to operate in "island mode" and power the critical loads circuit. The 100 kW CHP module is an inverter-based system with integral controls sufficient to enable single-DER microgrid island-mode operation and both electric and thermal load following. Although inverter-based systems reduce interconnection concerns due to their ability to rapidly disconnect the DER from the EPS in the event of a fault, probably the system would require protective relays and other measures to be approved for utility interconnection to operate in island mode, adding a minor to modest amount of cost and complexity. The 100 kW capacity is insufficient to serve OXP's peak critical load. It would be need to be controlled to operate in tandem with the BUG (and/or PV+BES), *e.g.*, with the CHP module operating at full output and the BUG varying its output as necessary to serve the remainder of the load. This would significantly increase controls complexity and cost. (Note that CHP manufacturer Tecogen is developing an inverter system capable of integrating their 100 kW CHP module with a PV or PV+BES system for tandem operations; this system should be available in 1–2 years.[262])

National Grid offers significant financial incentives for CHP on a per-kW basis (*e.g.*, $1000/kW), but currently there are no programs in Rhode Island that provide financial support for CHP energy production (*e.g.*, RECs or thermal energy credits). CHP is not eligible for RI's net metering program.

Complicating factors hinder the CHP option in this case. Under normal grid-connected conditions it would not run all the time for economic reasons; limited run-hours reduce the annual cost savings and prolong the payback period. The CHP module is relatively quiet, but would require an external dump radiator to discard excess thermal energy under certain operating conditions. Dump radiators include fans and they can be noisy, which could be a source of concern among the residents.

[262] http://www.prnewswire.com/news-releases/tecogen-introduces-bold-new-inverter-technology-with-inv-100e-300209740.html

3.3. HOMER Analysis

Inputs

OXP was modeled in largely the same way as BCV, with a few differences. A cost of $0.48/therm was used for natural gas. Electricity prices are shown in the table below; the blended rate for this facility (excluding fixed customer charges) was $0.132/kWh.

Table OXP-1: Oxford Place Electricity Rates

Fixed $/mo	Demand $/kW-mo	Supply $/kWh-mo	Delivery $/kWh-mo	Supply + Delivery $/kWh-mo	Reduced $/kWh-mo
135.00	9.17	0.107	0.036	0.142	0.112

Figure OXP-2: Oxford Place Electrical Load

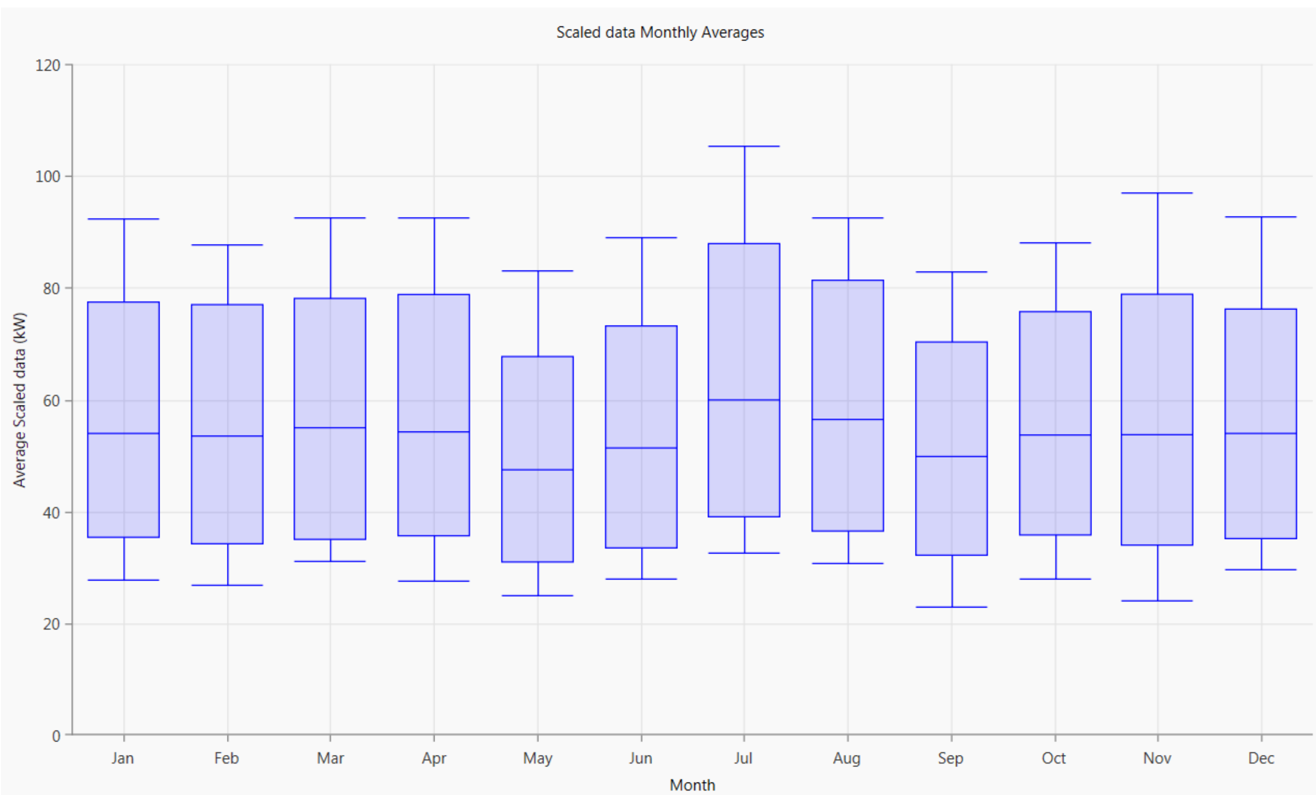


Image from HOMER Energy Software

Figure OXP-3: Oxford Place Thermal Load

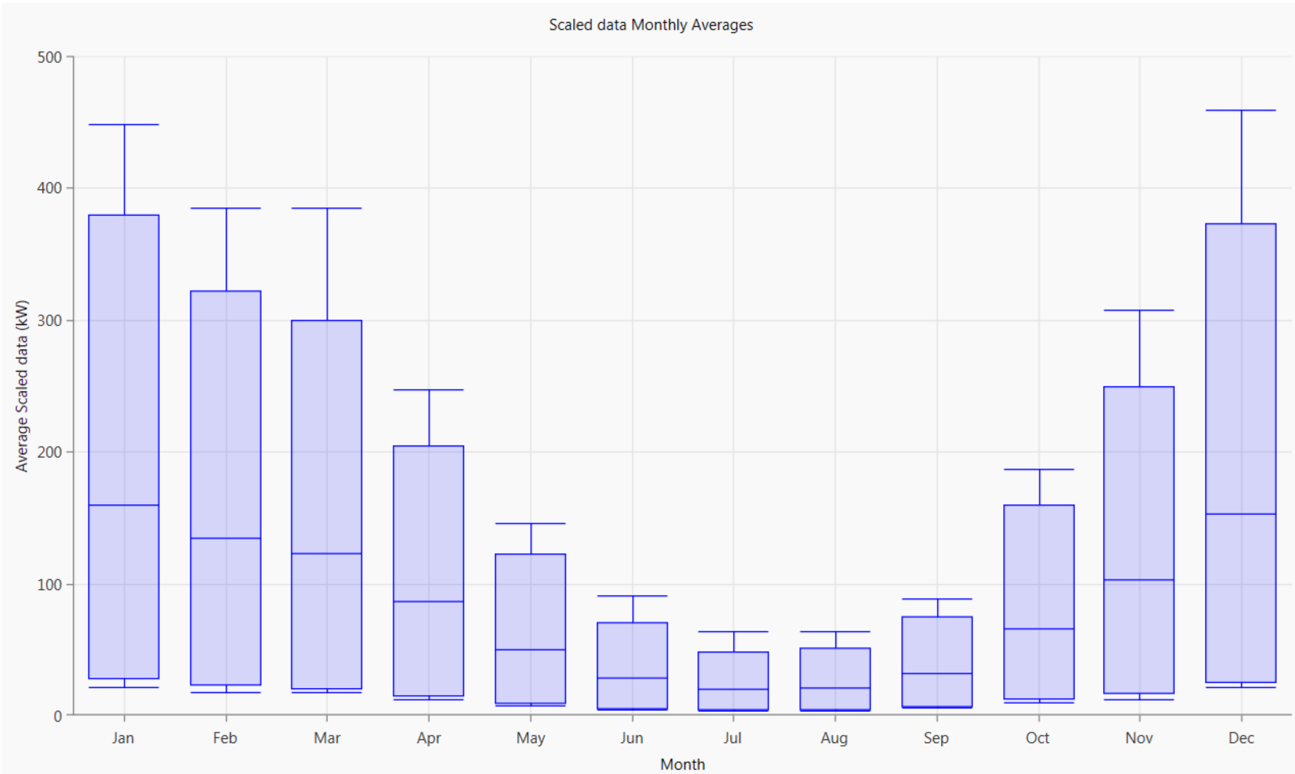


Image from HOMER Energy Software

The CHP analysis performed for this facility made use of the same unit costs: $4.50/kW and $4.78/hour of operation. Other component prices used in the OXP analysis are the same as those used for BCV.

Table OXP-2: Oxford Place Cost Assumptions

Component	Installed Cost	Operating Cost
Solar PV	$2,500 / kW	$10 / kW / yr
Natural Gas CHP	$4,500 / kW	$4.78 / hour
Inverter	$252 / kW	-
Batteries	$534 / kWh	$10 / kW / yr

<u>Model</u>

The recommended CHP system size was 100 kW, reflecting OXP's larger electrical and thermal loads. A scenario was run with the smaller, 35 kW system, to analyze the impact on project economics of system size relative to thermal load. A 100 kW solar array was chosen for the analysis based upon available roof area. Scenarios with and without the FIT were included.

Results and Analysis

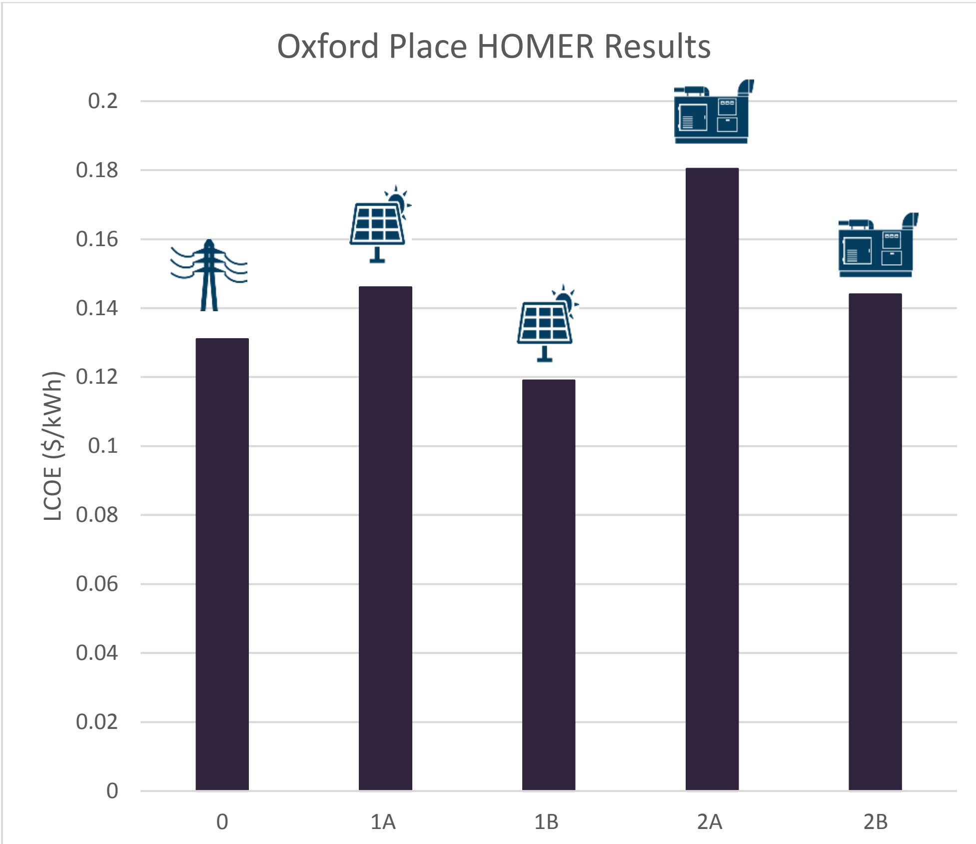
Table OXP-3: Oxford Place Scenario Overview

Scenario	Description
0	Grid
1A	Grid + Solar + Battery (without FIT)
1B	Grid + Solar + Battery (with FIT)
2A	Grid + CHP (100 kWe system)
2B	Grid + CHP (35 kWe system)

Table OXP-4: Oxford Place HOMER Results

Scenarios	PV	Battery	CHP	LCOE	Net Present Cost	Initial Capital Cost	Annual Cost	Simple Payback
	kW	kWh	kW	$/kWh	$	$	$/yr	yrs
0	-	-	-	$0.13	$1.23 M	0	78,146	-
1A	100	17	-	$0.15	$1.35 M	273,698	68,085	27.2
1B	100	17	-	$0.12	$1.14 M	273,698	54,985	11.8
2A	-	-	100	$0.18	$1.59 M	450,000	72,601	81.2
2B	-	-	35	$0.14	$1.33 M	157,500	74,254	40.5

Figure OXP-4: Oxford Place Scenario LCOE



The grid baseline case exhibits a LCOE of $0.13/kWh, reflecting the slightly higher cost of electricity compared to BCV. The results are more tightly grouped, with LCOEs ranging from $0.12/kWh to $0.18/kWh, but the ranking order is the same as that seen in BCV. Scenario 1B solar plus storage with FIT is the most economical choice, followed by the grid, solar plus storage without FIT, and CHP. Again, it is seen that the FIT makes the solar plus storage system an attractive option. The LCOE for solar is higher in this building since the PV size is smaller and the building load are larger than in BCV. Therefore, the favorable FIT makes less of an impact on LCOE.

The LCOE for the 100 kW CHP system is lower, owing to the larger thermal and electric loads in OXP than BCV. Economics appear better for the 35 kW system CHP than the 100 kW CHP system, with LCOE $0.14/kWh and $0.18/kWh, respectively. The 35 kW system operates almost continuously, exhibiting a capacity factor of 99% compared to a factor of 56% for the 100 kW system. The smaller CHP is more cost-effective in this scenario because there is a constant load large enough for it to serve, and it is therefore more fully utilized. CHPs are most economical when serving a facility's base thermal load, rather than a larger variable load. However, if resilience is the primary objective, it may not make sense to design a system that only meets a fraction of the desired load, or to select a synchronous generator that is more complex and costly to configure and interconnect for island mode operation.

Reductions in demand charges are likely to be unachievable, given the fluctuating output of the solar plus storage systems and the CHP systems. Because demand charges are calculated as the highest 15 minute-averaged demand per month, a much larger battery storage bank would be needed or the CHP unit would need to operate 100% of the time; neither is feasible.

An attempt was made to model a scenario that included both solar plus storage and CHP, but the HOMER program does not allow sell-back of electricity to be enabled or disabled for individual elements of a microgrid, only for the microgrid overall. This analysis will be performed using the CBAM tool.

Reductions in demand charges are modeled in HOMER, but cannot be guaranteed. This is due to intermittent output of the PV+BES systems and CHP system's low capacity factor (*i.e.*, it doesn't run all the time) and uncertain availability factor (*i.e.*, it might not be operating at any given time). These factors reduce the probability that DER output will coincide with unpredictable 15 minute periods of peak facility demand that determine demand charges. A much larger battery storage bank would be needed, or the CHP unit would need to operate 100% of the time, to provide demand charge reductions with high reliability. Because these savings cannot be completely relied upon, they are not included in the primary CBAM analysis. However, sensitivity to their inclusion is explored.

CBAM

Information used in the CBAM was identical to that used in the HOMER analysis, with a few exceptions. The cost of electrical infrastructure was included, and the size (and cost) of the battery storage system was increased to provide electricity for four hours at the facility's peak load. Table E-2 shows the assumed costs for these components. The O&M cost used for CHP was adjusted downwards from $4.78/hour to $3.89/hour. The $4.78/hour rate comes from contract clause using a 5% escalation rate over a base year O&M cost of $2.50; this escalation includes a rate of inflation. Because the CBAM makes use of base year dollars, that inflation assumption is removed using the average inflation rate for the Consumer Price Index over the last ten years, equal to 1.75%.[263] The remaining 3.25% escalation applied to the O&M contract cost of $2.50/hour gives an O&M cost of $3.89/hour. Electrical infrastructure costs were estimated to be $45,200.

[263] http://www.inflation.eu/inflation-rates/united-states/historic-inflation/cpi-inflation-united-states.aspx

Table OXP-5: Oxford Place CBAM Scenarios

	Solar	CHP	Batteries	Inverter
	kW	kW	kWh	kW
1. Solar	100	-	368	58
2. CHP	-	100	-	-
3. Both	100	100	368	58

For illustration, the following figures show the inputs and outputs used for the scenario with both solar PV and CHP. For scenarios with only one or the other, the appropriate inputs are deleted.

Figure OXP-5: Oxford Place Model Parameter Inputs

Model Inputs				
Analysis start year	2020			**Color Key**
Analysis end year	2045			Inputs
Analysis Period	25	Years		Outputs
				Benefits
Discount rate	6%	%		Costs
				Calculations
EIA Price Forecast: Choose scenario	No Energy Price Forecast			Reference Data
EIA Price Forecast: Choose sector	Residential			
Input Desired Grant Funding		$		
Desired Payback		years		
Output Funding Needed		$		

Figure OXP-6A: Oxford Place Financial and Energy Outputs for Solar PV and CHP Scenario (I)

Key Outputs		
	Financials	
Benefit-Cost Ratio	0.7473	
Simple Payback	24	years
Internal Rate of Return (IRR)	1%	%
Return on Investment (ROI)	0%	%
Project LCOE (electricity only)	$ (0.103)	$/kWh
Project LCOE (with thermal gen.)	$ (0.044)	$/kWh
	Microgrid Benefits	
Category	**Present Value**	**Annualized Value**
Avoided Boiler Fuel Purchases	$ 166,598.36	$ 13,032.44
Electricity Sales Revenue	$ 1,056,531.34	$ 82,648.98
Energy Efficiency Savings	$ -	$ -
Additional Benefits	$ -	$ -
Year 1 Grant	$ -	$ -
Salvage Value	$ -	$ -
TOTAL MG BENEFITS	$ 1,223,129.70	$ 95,681.42

Figure OXP-6B: Oxford Place Financial and Energy Outputs for Solar PV and CHP Scenario (II)

Microgrid Costs		
Category	**Present Value**	**Annualized Value**
Design Costs	$ -	$ -
Capital Investments	$ (956,328.00)	$ (74,810.40)
Non-Fuel Fixed O & M	$ (533,553.72)	$ (41,738.16)
Non-Fuel Variable O & M	$ -	$ -
MG Fuel Cost for CHP and Generation	$ (313,460.79)	$ (24,521.01)
MG Boiler Fuel Cost	$ (47,663.89)	$ (3,728.59)
MG Electricity Purchases	$ (874,262.00)	$ (68,390.65)
Energy Efficiency Costs	$ -	$ -
Additional Costs	$ -	$ -
TOTAL MG COSTS	$ (2,725,268.39)	$ (213,188.80)

Baseline Costs		
Category	**Present Value**	**Annualized Value**
Baseline Electricity Purchases	$ (874,262.00)	$ (68,390.65)
Baseline Thermal Fuel Purchases	$ (214,262.25)	$ (16,761.03)
TOTAL BASELINE COSTS	$ (1,088,524.24)	$ (85,151.68)

MG Benefits - Costs		
Category	**Present Value**	**Annualized Value**
MG Net Present Cost	$ (1,502,138.69)	$ (117,507.38)
MG Net Present Cost Relative to Baseline	$ (413,614.45)	$ (32,355.70)

Energy		
Baseline Electricity Consumption	470,471	kWh/year
Reduced Electricity Consumption	470,471	kWh/year
Baseline Electricity Demand	105	Peak kW
Reduced Electricity Demand	105	Peak kW
Electricity Generated	582,787	kWh/year
Electricity Purchased	-	kWh/year
Excess Electricity	112,317	kWh/year
Baseline Thermal Load	2,429	MMBtu/year
Reduced Thermal Load	2,429	MMBtu/year
CHP Thermal Generation	2,723	MMBtu/year
Boiler Thermal Generation	(294)	MMBtu/year

Figure OXP-7: Oxford Place Cash Flow Diagrams for Solar PV and CHP Scenario

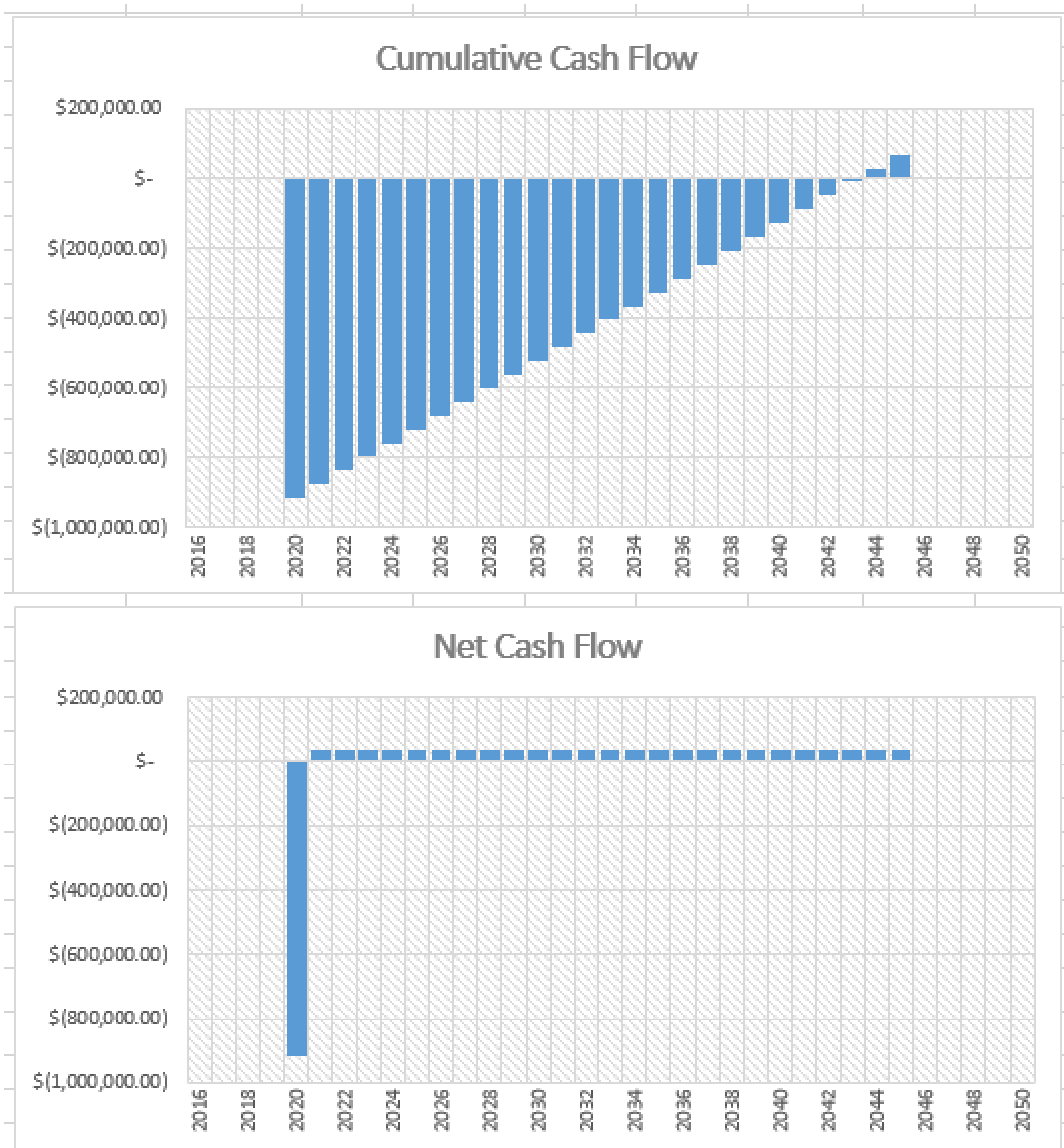


Figure OXP-8: Oxford Place Electricity Demand Inputs for Solar PV and CHP Scenario

	Electricity Consumption													
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM	YEAR AVE
Facility	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
Oxford Place	39573	39573	39573	39573	35127	37336	44231	40584	36184	39573	39573	39573	470471	39206
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
													0	0
SUM	39573	39573	39573	39573	35127	37336	44231	40584	36184	39573	39573	39573	470471	39206

	Electricity Demand												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM
Facility	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW	kW
Oxford Place	92	88	93	93	82	91	105	93	83	88	97	93	1097
													0
													0
													0
													0
													0
													0
													0
													0
													0
SUM	92	88	93	93	82	91	105	93	83	88	97	93	

Figure OXP-9: Oxford Place Thermal Demand and Utility Rate Inputs for Solar PV and CHP Scenario

					Thermal Fuel Purchases												
	Fuel Type	Fuel Cost	Boiler / Furnace Name	Boiler / Furnace Efficiency	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM
Facility		$/MMBtu		%	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu
Oxford Place	Natural Gas	4.8	Boiler I	75%	531	448	403	285	169	94	66	70	104	219	345	505	669
																	0
																	0
																	0
																	0
																	0
																	0
																	0
																	0
																	0
SUM					531	448	403	285	169	94	66	70	104	219	345	505	3239

UTILITY ELECTRICITY RATES			
	Fixed Charges	Energy Charges	Demand Charges
Facility	$/month	$/kWh-mo.	$/kW-mo.
Oxford Place	$ 130.00	$ 0.11	$ 9.17
SUM			

REFERENCE HEATING UNIT CONVERTER			
	MMBtu	0.00	Btu
		0.0000	MMBtu
		0.00	kWh
		0.00	Therm
		0.00	Ccf Natural Gas

Figure OXP-10: Oxford Place Generating Resources for Solar PV and CHP Scenario

GENERATING ASSETS

Electricity Generating Resources					
	Rated Power	Fuel Type	Fuel Consumption	Fuel Cost	Compensated for Overgeneration?
Resource	kW		MMBtu/kWh	$/MMBtu	
Solar I	100	Electricity	0	$ -	Yes
SUM	100				

Combined Heat & Power Resources								
	Rated Power	Fuel Type	Fuel Consumption	Fuel Cost	Compensated for Overgeneration?	Maximum Thermal	Associated Facility:	Offset Fuel From:
Resource	kW		MMBtu/kWh	$/MMBtu		MMBtu/hr		
CHP I	100	Natural Gas	0.0101	$ 4.80	Yes	0.5903	Oxford Place	Boiler I
SUM	100							

Figure OXP-11: Oxford Place Electrical and Thermal Generation for Solar PV and CHP Scenario

ELECTRICAL GENERATION

	Electricity Generation												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM
Resource	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	
Solar I	5812	7152	10257	11206	12916	12927	12903	11914	9971	8207	5490	4934	113687
CHP I	39945	35922	40582	39144	35403	36828	44812	42052	35454	40108	38721	40129	469100
													0
													0
													0
													0
													0
													0
													0
													0
SUM	45757	43073	50839	50350	48320	49755	57716	53966	45425	48315	44211	45062	582787

THERMAL GENERATION

	CHP Thermal Generation												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR SUM
Resource	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	MMBtu	
CHP I	231.9	208.5	235.6	227.2	205.5	213.8	260.1	244.1	205.8	232.8	224.8	233.0	2723.16193
													0
													0
													0
													0
													0
													0
													0
													0
													0
SUM	231.8845399	208.528009	235.581738	227.2341946	205.5189841	213.7889763	260.1387589	244.1137846	205.8140141	232.8297338	224.7776264	232.9515707	2723.16193

Figure OXP-12: Oxford Place Efficiency Inputs [*None Entered*]

ENERGY EFFICIENCY							
ENERGY EFFICIENCY UPGRADES							
Facility	Reduction of Energy Demand	Reduction of Energy Usage	Reduction of Heating Demand	Offset Fuel From:	Efficiency Capital Cost	Efficiency O&M Cost	Description of ECM Package
	kW/month	kWh/month	MMBtu/month		$	$/Year	
SUM	0	0	0		$ -	$ -	

Figure OXP-13: Oxford Place Capital and Fixed O&M Cost Inputs for Solar PV and CHP Scenario

MICROGRID COSTS

CAPITAL COSTS			
Component	Installed Cost	Year of Purchase	Lifetime
	$		Years
Solar I	$ 250,000.00	2020	25
Batteries	$ 196,512.00	2020	25
CHP I	$ 450,000.00	2020	25
Inverter	$ 14,616.00	2020	25
Electrical Hardware	$ 45,200.00	2020	25
SUM	$ 956,328.00		

FIXED NON-FUEL O & M COSTS			
Component	Cost	Start Year	End Year
	$		
Solar I	$ 1,000.00	2020	2045
Batteries	$ 3,680.00	2020	2045
CHP I	$ 34,030.00	2020	2045
SUM	$ 38,710.00		

Figure OXP-14: Oxford Place Variable O&M Cost Inputs [*None Entered*]

VARIABLE NON-FUEL O & M COSTS: MANUAL INPUT		
Component	Cost	Year
	$	
SUM	$ -	

VARIABLE NON-FUEL O&M: $/kWh INPUT	
Component	Cost
	$/kWh
SUM	0

'ARIABLE NON-FUEL O&M: $/MMBtu INPU	
Component	Cost
	$/MMBtu
SUM	0

Figure OXP-15: Oxford Place Additional Cost Inputs [*None Entered*]

ADDITIONAL ONE-TIME COSTS			
Component	Cost	Year	Description
SUM	$ -		

DESIGN COSTS	
Component	Cost
	$

ADDITIONAL ONGOING COSTS				
Component	Cost	Start Year	End Year	Description
SUM	$ -			

Figure OXP-16: Oxford Place Benefits Inputs for Solar PV and CHP Scenario

MICROGRID BENEFITS

COMPENSATION FOR OVERGENERATI		Option 1: Not Behind the Meter		Option 2: Behind the Meter						
Generating Resource	Revenue Model	Fixed Payments	Energy Payments	Associated Facility	Price Tier 1: Max % Load	Fixed Payments	Energy Payments	Price Tier 2: Max % Load	Fixed payments	Energy Payments
		$/month	$/kWh		%	$/month	$/kWh	%	$/month	$/kWh
Solar I	Not behind the met	$ -	$ 0.23	Oxford Place	100%	$ -	$ 0.11	125%	$ -	$ 0.08
CHP I	Behind the meter	$ -	$ -	Oxford Place	100%	$ -	$ 0.11		$ -	$ -
SUM		$ -	$ 0.23							

ADDITIONAL ONE-TIME BENEFITS			
Component	Benefit	Year	Description
SUM	0		

ADDITIONAL YEARLY BENEFITS				
Component	Benefit	Start Year	End Year	Description
SUM	0			

Conclusions and recommendations

As shown in the Babcock Village analysis, the CBAM tool can be used to explore the economic implications of a number of different policy decisions for Oxford Place.

The tool was used to analyze three different scenarios: solar PV (scenario 1), CHP (scenario 2), and both PV and CHP (scenario 3). Configurations include a 100 kW solar array, 100 kW micro-CHP, and both together. Scenarios 1 and 3 include batteries and assume a feed-in-tariff (FIT).

Table OXP-6 shows that scenarios 1 and 3 pay back during the 25 year analysis period. Both appear to be less attractive at Oxford Place than at Babcock Village. The expected costs for the battery array scale with size, and the array is about twice as big as the one needed at Babcock Village to meet resilience requirements. Smaller suitable roof area makes the solar array smaller, which then generates less revenue. Combined, these factors extend the payback periods. Conversely, CHP appears to be more attractive at Oxford Place. This can be attributed to the larger electrical and thermal loads, which allow for the sizing of a larger unit.

Table OXP-6: CBAM Results – No Grant Support

	Benefit-Cost Ratio	Simple Payback	IRR	ROI	LCOE	LCOE (Electrical and Thermal Gen.)
		years	%	%	$/kWh	$/kWh
1. Solar	0.62	24	1%	0%	$0.46	$0.46
2. CHP	0.78	No Payback in Analysis Period	0%	0%	$0.11	$0.04
3. Both	0.81	20	2%	1%	$0.10	$0.04

The levelized cost of energy (LCOE) in CBAM uses the total cost of supplying OXP's energy needs. In Table OXP-7, the fifth column entitled "LCOE" divides that cost by the electricity produced only, while the sixth column entitled "LCOE (Electrical and Thermal Gen.)" divides the total cost by electric and thermal energy produced.

The LCOE appears to be higher than that shown in HOMER for solar. This can be attributed to the inclusion of electrical infrastructure costs and a larger battery array. The additional battery array costs are necessary to achieve resilience objectives, but introduce additional sizable capital and O&M costs. The electrical infrastructure also introduces additional costs. The LCOE of CHP is lower because that configuration does not include batteries, and produces much more energy.

CBAM can be used to analyze the effect of energy price escalation using two scenarios provided by the U.S. Energy Information Administration (EIA). This escalation does not include inflation, it represents forecasted changes in the real value of electricity and fuel. This has a small, but noticeable effect on the results. Table OXP-7 shows results using the "No Clean Power Plan" scenario. All three scenarios become more attractive.

Table OXP-7: CBAM Results – No Grant Support, "No Clean Power Plan" Price Escalation

	Benefit-Cost Ratio	Simple Payback	IRR	ROI	LCOE	LCOE (Electrical and Thermal Gen.)
		years	%	%	$/kWh	$/kWh
1. Solar	0.72	19	2%	1%	$0.50	$0.50
2. CHP	0.89	18	3%	2%	$0.12	$0.04
3. Both	0.92	16	5%	3%	$0.10	$0.04

CBAM was used to identify the grant funding amount needed to shorten the payback period to 15 years for each scenario. Results are shown in Table OXP-8.

Table OXP-8: CBAM Results – Grant Support for 15-Year Payback

	Grant Amount	Benefit-Cost Ratio	Simple Payback	IRR
	$		years	%
1. Solar	$172,000.00	0.92	15	4%
2. CHP	$200,000.00	0.96	15	4%
3. Both	$203,000.00	0.94	15	4%

The first column shows the grants required. The smallest grant amount is required for the solar array, but this option also generates less energy for the facility, requiring electricity purchases from the utility.

An alternative grant funding strategy is one that covers only electrical equipment and batteries. The results of this type of policy are shown in Table OXP-9.

Table OXP-9: CBAM Results – Grant Support for Electrical Infrastructure and Batteries

	Grant Amount	Benefit-Cost Ratio	Simple Payback	IRR
	$		years	%
1. Solar	$256,328.00	1.07	11	8%
2. CHP	$45,200.00	0.82	24	1%
3. Both	$256,328.00	0.97	14	5%

Funding for the electrical infrastructure in scenarios 1 and 3 results in a grant of $256,328. This amount is larger because it includes batteries and an inverter. This decreases the paybacks to 11 and 14 years, respectively. The grant amount for CHP is lower at $45,200; this scenario pays back in 24 years at this level of funding.

Whether the electricity produced by the solar array is compensated via a FIT or net metering has a significant impact on solar economics, as shown in Table OXP-10. The first two rows show solar with and without the FIT. The third row demonstrates the size of grant that would be needed to bring the payback for a net-metered microgrid to a 15-year payback. $382,000 would be needed to bring scenario 1 to a 15-year payback; solar economics are highly sensitive to the FIT assumption.

Table OXP-10: CBAM Results – Comparison of FIT and Net Metering

	FIT	Grant Amount	Benefit-Cost Ratio	Simple Payback	IRR	LCOE
	Y/N	$		years	%	$/kWh
1. Solar	Y	$0.00	0.62	24	1%	$0.46
	N	$0.00	0.30	No Payback in Analysis Period	-6%	$0.52
	N	$382,000.00	0.97	15	4%	$0.39

As described in the HOMER section, demand charges are calculated as the highest 15-minute average demand in a monthly period. This means that reducing that charge requires extremely reliable electricity production. In this early stage analysis, the assumption is made that that level of reliability is not guaranteed. However, it is useful to explore the impact on project economics of relaxing that assumption- particularly for the CHP unit. Using the “Additional Yearly Benefits” box on the “Design Inputs” tab of CBAM, an estimated $7,714 annual demand charge savings are input. This value is calculated to be the difference between baseline demand charges and the demand charges calculated in HOMER. Including this source of savings has a positive impact on the CHP scenarios: Table OXP-11 shows how the economics change. The first row shows scenario 2 with no grant, the second row shows the grant funding needed to get to a 15 year payback, and the third row shows the impact of an electrical infrastructure grant. Funding needed to achieve a 15-year payback period declines to $77,000 from $200,000.

Table OXP-11: CHP Results with Demand Charge Reductions

	Grant Amount	Benefit-Cost Ratio	Simple Payback	IRR
	$		years	%
2. CHP	$0.00	0.88	18	3%
	$77,000.00	0.95	15	4%
	$45,200.00	0.92	17	4%

Solar plus storage is also recommended as a resilient backup power system for Oxford Place. The available rooftop area is smaller than Babcock Village, which results in a smaller array and less energy produced. However, with a properly sized battery storage system, energy can be stored and used to provide resilient power supply for the desired duration. CHP economics don’t appear quite as strong as solar, and would require greater grant funding. For short durations of guaranteed power, the economics of a solar array make it the more attractive option. However, a 100 kW CHP unit would supply more power than a 100 kW solar array on a continuous basis. Coupled with batteries, the solar array supplies the power needed for a 4-hour duration. If guaranteed backup power is desired indefinitely (assuming an uninterrupted supply of natural gas), CHP would be the superior choice. Recommended system choice depends upon desired duration of guaranteed backup power.

As with the Babcock Village analysis, these results are strongly dependent upon assumptions made. Most notably, variations in the use of a FIT, demand charge savings, the O&M cost, and unit lifetime can change the relative attractiveness of solar and CHP. As more detailed design is completed, uncertainty in modeled results will decline.

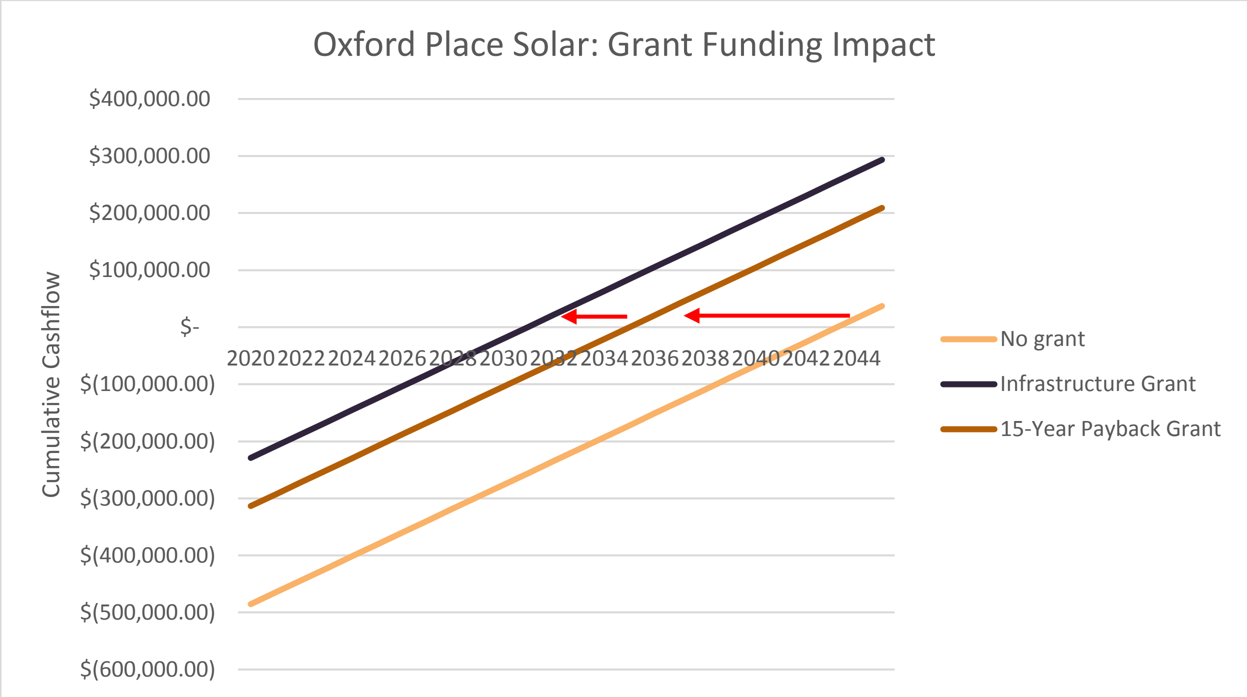
Although a CHP system capable of grid-independent operation is not shown to be a highly attractive option in this case, this indication should not be taken to apply to every situation. Facilities with larger or more constant thermal loads would present more conducive conditions. The additional equipment required to make a CHP system capable of grid-independent operations adds significant cost and extends the payback period. If we assume that demand charge reductions were greater, the economics would be more favorable. For example, one CHP system manufacturer we interviewed reported that operational data on hundreds of installed systems in the 30–100 kW size range suggest that we could apply an assumed average of 9 months' worth of demand savings at 75% system output, which could reduce the payback period in this case to a 6–7 year range. Strong policy support and incentives can have significant effects on CHP deployment; see section D2.4 for further discussion.

For illustration, the effect grant funding has on the payback period (where the cumulative cash flow becomes positive) for solar scenarios is shown with red arrows in Figure OXP-17.

Table OXP-12: Grant funding options

Solar only, FIT		
No grant	**15-Year Payback Grant**	**Infrastructure-Only Grant**
$0.00	$172,000.00	$256,328.00

Figure OXP-17: Grant Impact on Cumulative Cashflow



APPENDIX A: RISKS TO THE RHODE ISLAND ELECTRIC GRID

This appendix describes hazards that pose risks of long-duration power outages (defined here as lasting longer than 3 days) and "Black Sky events" that cause very long duration outages (defined here as lasting longer than one week, and potentially many weeks or months). Each hazard is paired with a microgrid policy observation or suggestion.

The authors' descriptions do not always align with the 2011 Rhode Island Hazard Mitigation Plan (RIHMP) and 2014 update; refer to both documents for more specific information (*e.g.*, county- and municipality-specific hazard exposure, hazard characterization and rankings).

Figure AA-1: RIHMP Hazards[264]

Rhode Island Hazard Mitigation Plan
2014 Update

Wind Related Hazards	Winter Related Hazards	Flood Related Hazards	Geologic Related Hazards	Additional Hazards
Storm Surge	Snow	Riverine Flooding	Earthquakes	Wildfire
Hurricanes	Ice	Flash Flooding		Drought
Tornadoes	Extreme Cold	Urban Flooding		Extreme Heat
High Winds		Coastal Flooding		
		Climate Change and SLR		
		Coastal Erosion		
		Dam Breach		

Wildfire and extreme heat were added to the vulnerability assessment for the 2014 plan update.

The Rhode Island Energy Assurance Plan (RIEAP) cites six priority hazards listed in the 2011 Rhode Island Hazard Mitigation Plan (RIHMP), noting: "The hazards that are considered to be of greatest consequence are hazards associated with extreme weather events, specifically hurricanes and winter snow storms."[265]

- Flood-related
- Wind-related
- Winter-related
- Drought
- Flash floods
- Geologic-related

[264] RIEMA, *Rhode Island 2014 Hazard Mitigation Plan Update*, 2014, p. 35. Accessed at: http://www.riema.ri.gov/resources/emergencymanager/mitigation/documents/RI%20HMP_2014_FINAL.pdf
[265] RIEMA, *Rhode Island State Hazard Mitigation Plan*, 2011, cited in RIEAP, p. 9-4.

Surveyed electricity and petroleum industry stakeholders identified natural disasters as the biggest threat to their energy supplies, while natural gas stakeholders described a transmission pipeline disruption as the biggest threat to their energy supply.[266]

The RIEAP uses RIHMP hazard classifications, with three main categories: Natural (*e.g.*, extreme weather, epidemics, wildfires), Technological (*e.g.*, equipment failures), and Human (*e.g.*, intentional harm or human error accidents). The authors group hazards into natural and man-made categories, but reference the RIHMP classifications.

Black Sky hazards and High Frequency, Low Impact events

Extreme hazards pose risks of large-scale, long-duration outages with potentially catastrophic impacts. These have been termed "High-Impact, Low-Frequency (HILF) Events" and "Black Sky Hazards"; the authors will use both terms. Events that damage or destroy critical infrastructure with long replacement times can disable energy networks for weeks to months. Central power stations, high voltage transformers and other complex and often custom-built equipment have limited spares or options for replacement, and key components are often made overseas. The authors suggest defining "long duration" outages as those exceeding 3 days, and "Black Sky Events" as outages exceeding one week.

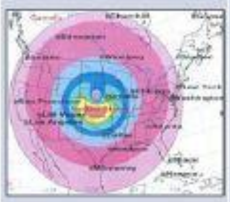
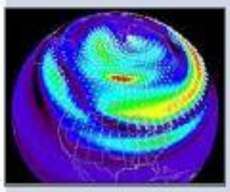
NERC and the U.S. Department of Energy (USDOE) convened a 2009 workshop and resulting 2010 report on HILF events. "These risks have the potential to cause catastrophic impacts on the electric power system, but either rarely occur, or, in some cases, have never occurred. Examples of HILF risks include coordinated cyber, physical, and blended attacks, the high-altitude detonation of a nuclear weapon, and major natural disasters like earthquakes, tsunamis, large hurricanes, pandemics, and geomagnetic disturbances caused by solar weather. HILF events truly transcend other risks to the sector due to their magnitude of impact and the relatively limited operational experience in addressing them. Deliberate attacks (including acts of war, terrorism, and coordinated criminal activity) pose especially unique scenarios due to their inherent unpredictability and significant national security implications. As concerns over these risks have increased, the electric sector is working to take a leadership position among other Critical Infrastructure and Key Resource (CIKR) sectors in addressing these risks."[267]

The Electric Infrastructure Security Council (EISC) "facilitates national and international collaboration and planning to protect our societies' critical utilities against uniquely severe Black Sky Hazards." EISC defines a "black sky hazard" as "a catastrophic event that severely disrupts the normal functioning of our critical infrastructures in multiple regions for long durations." Manmade black sky hazards include high-altitude electromagnetic pulse (EMP), Intentional Electromagnetic Interference (IEMI), cyber terrorism, and coordinated physical assault. Natural black sky hazards include high-magnitude earthquake seismic event, geomagnetic disturbance

[266] RIEAP, 2012, pp. 3-2 & 3-3.
[267] NERC and DOE, *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*, 2010, p. 8.

(severe space weather), and hurricanes and other severe weather events.[268] EISC focuses on catastrophic risks associated with "E-Threats," comprising space weather and man-made weapons that cause similar effects.[269]

Figure AA-2: E-Threats[270]

	THREAT	Environments	Susceptible Systems
	High Altitude EMP	Fast Pulse E1	Long-line and short-line electrical and electronic systems
		Slow Pulse E3	Long-line network systems incl. electric power grid, terrestrial and undersea comm. lines, pipelines
	Solar Super Storms	Geomagnetic Disturbance	Long-line network systems incl. electric power grid, terrestrial and undersea comm. lines, pipelines

The following section briefly describes natural and manmade hazards, and suggests potential policy responses. These are acute hazards (although pandemics would develop over longer periods). Climate change is a slowly occurring hazard, but can be considered a "force multiplier" capable of amplifying natural hazards. (Anthropogenic or human-influenced climate change could be described as a "man-made natural hazard".)

Policy recommendation: OER could set minimum standards for hazard mitigation measures in funded microgrids, such as being able to withstand a designated wind speed. However, using preferential scoring in funding applications could provide both incentives and flexibility for microgrid developers to include varied threat mitigation measures. This could be more cost-effective and user-friendly than simply requiring broad ranges of mitigation measures.

[268] www.eiscouncil.com

[269] From EISC, *E-Pro Handbook*, 2014, p. ii: "Electromagnetic threats (E-threats) to the power grid include two effects. Severe Space Weather refers to a periodic disturbance of the sun's corona which can cause potentially damaging current to flow through power grids, due to large variations induced in the earth's magnetic field (Geomagnetic Disturbances – GMD). ; Electromagnetic Pulse (EMP), resulting from a nuclear detonation in the upper atmosphere, can cause power grid disturbances similar to Severe Space Weather, as well as a very intense, short pulse that can damage electrical equipment."

[270] Testimony of George H. Baker, Joint Hearing on "The EMP Threat: The State of Preparedness against the Threat of an Electromagnetic Pulse (EMP) Event", May 13, 2015, p. 2, accessed at: https://oversight.house.gov/wp-content/uploads/2015/05/Baker-Statement-5-13-EMP.pdf

Natural hazards

Weather – Wind: tree fall, blown debris, severe storms. Damage to overhead transmission and distribution (T&D) lines can be extensive in severe wind events, particularly if large numbers of trees are felled and block roads that hinder response (especially where wires are entangled in the trees, preventing local authorities from clearing them without utility crew assistance). In 2011 Hurricane Irene and nor'easter Storm Alfred destroyed an estimated 1%–2% of the trees in Connecticut; each event caused widespread blackouts affecting over 800,00 customers that took 9–12 days in many locations to fully restore service. The utilities estimated that a Category 3 hurricane landfall could destroy 70%–80% of Connecticut's trees, requiring up to a month to restore service.[271]

"During Hurricane Sandy, approximately 120,000 electric customers lost power (nearly 25% of the state's 482,000 customers), and 1,200 natural gas customers lost service (out of 252,000 gas customers). In addition, nine substations went out of service; 1,433 sections of wires went down; and 63 poles were broken. Five days passed until National Grid was able to fully restore electric service to 100% of customers."[272]

Hurricanes are the most powerful wind events; categories and characteristics are depicted below.

[271] *Report of the Two Storm Panel*, 2012, p. 8.
[272] OER, RFP # 7549749 *Resilient Microgrids for Critical Services*, 2015, p. 5.

Figure AA-3: Hurricane Intensity Scale[273]

Table 10. Saffir/Simpson Scale of Hurricane Intensity. Source: NWS NCDC.

Wind Speed	Typical Effects
Category One Hurricane – Weak	
74-95 MPH (64-82kt)	Minimal Damage: Damage is primarily to shrubbery, trees, foliage, and unanchored mobile homes. No real damage occurs in building structures. Some damage is done to poorly constructed signs.
Category Two Hurricane – Moderate	
96-110 MPH (83-95kt)	Moderate Damage: Considerable damage is done to shrubbery and tree foliage, some trees are blown down. Major structural damage occurs to exposed mobile homes. Extensive damage occurs to poorly constructed signs. Some damage is done to roofing materials, windows, and doors; no major damage occurs to the building integrity of structures.
Category Three Hurricane – Strong	
111-130 MPH (96-113kt)	Extensive damage: Foliage torn from trees and shrubbery; large trees blown down. Practically all poorly constructed signs are blown down. Some damage to roofing materials of buildings occurs, with some window and door damage. Some structural damage occurs to small buildings, residences and utility buildings. Mobile homes are destroyed. There is a minor amount of failure of curtain walls (in framed buildings).
Category Four Hurricane - Very Strong	
131-155 MPH (114-135kt)	Extreme Damage: Shrubs and trees are blown down; all signs are down. Extensive roofing material and window and door damage occurs. Complete failure of roofs on many small residences occurs, and there is complete destruction of mobile homes. Some curtain walls experience failure.
Category Five Hurricane – Devastating	
Greater than 155 MPH (135kt)	Catastrophic Damage: Shrubs and trees are blown down; all signs are down. Considerable damage to roofs of buildings. Very severe and extensive window and door damage occurs. Complete failure of roof structures occurs on many residences and industrial buildings, and extensive shattering of glass in windows and doors occurs. Some complete buildings fail. Small buildings are overturned or blown away. Complete destruction of mobile homes occurs.

The National Oceanic and Atmospheric Administration (NOAA) notes that although climate change is projected to increase the intensity and rainfall rates of tropical storms globally, Atlantic Basin hurricanes are projected to decrease in frequency, increase slightly in intensity, and have increased rainfall rates.[274]

Severe wind events that are smaller than hurricanes and tropical storms can also cause significant outages. The June 2012 "North American Derecho" severe thunderstorm complex came during a heat wave, caused 22 deaths and knocked out power for over 4.2 million customers in 10 states for up to 2 weeks in some areas.[275] Tornadoes can cause multiday outages in localized impact areas, and possibly longer outages if they happen to destroy critical EPS components.

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[273] RIEMA, *Rhode Island 2014 Hazard Mitigation Plan Update*, 2014, p. 59.
[274] https://www.gfdl.noaa.gov/global-warming-and-hurricanes/
[275] https://en.wikipedia.org/wiki/June_2012_North_American_derecho

Rhode Island is subject to both hurricanes and nor'easters. "The comparison of hurricanes to nor'easters reveals that the duration of high surge and winds in a hurricane is 6–12 hours while a nor'easter's duration can be from 12 hours to 3 days. The amount of damage resulting from a strong hurricane is often more severe than a nor'easter, but historically, Rhode Island has suffered more damage from nor'easters because of the greater frequency in which they occur."[276]

Category 3 hurricanes in 1938 and 1954 were black sky events for parts of Rhode Island. "The [Category 3] hurricane of September 21, 1938 brought major devastation to the State, with 262 persons losing their lives and damage estimated at $100 million. The coastal area from Westerly to Little Compton experienced the heaviest damage, but there was no tidal wave, since the storm hit at ebb tide. Sustained winds of 95 MPH recorded; damage estimated at $100 million; 262 fatalities. Tide 15 feet above mean sea level (at USGS gage in Westerly). Virtually all the State was without power. Ten percent of electric customers still without power 12 days after hurricane.

"On August 31, 1954, Hurricane Carol swept into Rhode Island with little warning. The result was 19 deaths and $200 million in property damage. The storm center passed to the west of Providence and came at high tide. The central area of Providence was flooded to a depth of 13 feet, and 3,500 cars were inundated in the downtown areas…. There were 19 fatalities in New England, $200 million property damage and 13' flooding. In Providence, wind speed of 90 MPH, with 115 MPH gusts; nearly 3,800 homes destroyed. Tide 12.2 feet above mean seal level (at USGS gage in Westerly). Most of State without power. Four days after storm, approximately 50% had power restored; 90% after seven days."[277]

<u>Policy recommendation</u>: OER could consider requiring microgrid components to be able to withstand hurricane-force winds, *e.g.*, a Category I hurricane (as does Connecticut's program), or awarding scoring points for those that do. OER might consider having microgrid developers demonstrate that the host facility can itself withstand the wind forces required of the microgrid installation. Florida's SunSmart E-Shelter program installed solar-plus-storage installations only at Enhanced Hurricane Protected Area schools designed to withstand hurricanes and serve as public emergency shelters.[278] Geographic dispersion of microgrids could contribute to risk mitigation.

Weather – Wind: storm surge, seawater inundation. Storm surges are primarily a wind-driven phenomenon, also influenced by tides and Sea Level Rise (SLR). Surges can cause severe damage to electrical and even gas pipeline infrastructure but in coastal areas if protective hardening, flood proofing and other countermeasures are not sufficient. Rhode Island has significant coastal exposure.

The U.S. Global Change Research Program (USGCRP) reports that regional "[c]oastal flooding

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[276] RIEMA, *Rhode Island 2014 Hazard Mitigation Plan Update*, 2014, p. 60.
[277] RIEMA, *Rhode Island 2014 Hazard Mitigation Plan Update*, 2014, pp. 61–62.
[278] http://www.fsec.ucf.edu/En/education/sunsmart/index.html

has increased due to a rise in sea level of approximately 1 foot since 1900", and projects that the northeast will experience higher sea level rise then the global average, due to land subsidence rates as well as climate change.[279]

Rhode Island has significant coastal exposure to storm surges, and past events have produced higher flood levels in Providence than in Newport. "Hurricane wind damages can be costly but storm surge is by far the most destructive force acting on the Rhode Island coast. The highest storm surges recorded at the Newport tide gauge were 9.45' and 6.76' above MHHW during the Great September Hurricane of 1938 and Hurricane Carol, August 1954, respectively. By comparison, the Providence gauge recorded surges of 12.66' and 9.96' above MHHW respectively."[280] This poses a significant hazard to Rhode Island's petroleum supply because 5 of the state's 6 major liquid fuels terminals are located there, all are subject to storm surge damage, and as of 2012 none of these facilities has backup generation sufficient to power their operations.[281]

<ins>Policy recommendation</ins>: OER could consider requiring microgrid components to be able to withstand seawater inundation, or awarding scoring points for those that do. Alternately OER could require that microgrids not be located in an inundation zone, or incorporate wet- or dry-floodproofing design features and a flood continuity of operations plan. Geographic dispersion of microgrids could contribute to risk mitigation. OER should prioritize Providence-area liquid fuel terminals for energy assurance and storm surge resilience upgrades.

Weather – Precipitation: rain, freshwater inundation. Freshwater flooding can damage insufficiently-protected critical infrastructure. The frequency of heavy downpours is projected to increase due to climate change, and average winter and spring precipitation is projected to increase. According to the USGCRP: "The Northeast has experienced a greater recent increase in extreme precipitation than any other region in the United States; between 1958 and 2010, the Northeast saw more than a 70% increase in the amount of precipitation falling in very heavy events (defined as the heaviest 1% of all daily events)."[282]

<ins>Policy recommendation</ins>: OER could consider requiring microgrid components to be able to withstand freshwater inundation, or awarding scoring points for those that do. Alternately OER could require that microgids not be located in an inundation zone, or incorporate flood mitigation design features and a flood continuity of operations plan. Geographic dispersion of microgrids could contribute to risk mitigation.

Weather – Precipitation: snow, ice. Extremely cold temperatures can increase natural gas demand, causing spikes in electricity prices. Early snowfall from Storm Alfred in October 2011 caught trees in leaf, which along with high winds caused extensive treefall that downed power lines, leaving over 3 million homes and businesses without power for up to 11 days in some

[279] USGCRP 2014, accessed at: http://nca2014.globalchange.gov/report/regions/northeast
[280] RIEMA, *Rhode Island 2014 Hazard Mitigation Plan Update*, 2014, p. 60.
[281] RIEAP, 2012,
[282] USGCRP 2014, accessed at: http://nca2014.globalchange.gov/report/regions/northeast

areas, at a total cost of $1–$3 billion.[283] Ice storms can be very damaging to overhead power lines and towers. The "Great Ice Storm" of January 1998 that affected parts of Canada and the northern U.S. destroyed approximately 1,000 steel transmission towers and 35,000 wooden utility poles, knocking out power to more than 4 million people; three weeks later thousands of people remained without electricity.[284]

According to the USGCRP, winter and spring precipitation is projected to increase in the Northeast due to climate change. "The frequency, intensity, and duration of cold air outbreaks is expected to decrease as the century progresses, although some research suggests that loss of Arctic sea ice could indirectly reduce this trend by modifying the jet stream and mid-latitude weather patterns."[285]

Policy recommendation: OER could consider requiring or preferential scoring for microgrids to have a contingency plan for maintaining components vulnerable to ice and snow (*e.g.*, clearing PV panels, temperature control for battery systems), and for microgrids that provide four-season mission-critical functionality such as continuity of operations or shelter in place. Geographic dispersion of microgrids could contribute to risk mitigation.

Weather – High heat, drought, wildfires. High temperatures can stress power lines and other equipment, and cause cooling-driven peak day power demand spikes that reach maximum EPS demand levels. High surface water temperatures can restrict power production if cooling systems cannot operate within design ranges. Connecticut's Millstone nuclear reactor had to shut down Unit 3 for almost 2 weeks in August 2012 when Long Island Sound water temperatures exceeded the 75°F maximum allowed for cooling use, leading the Nuclear Regulatory Commission (NRC) in 2014 to permit Units 2 and 3 to use 80°F water.[286] Massachusetts' Pilgrim Nuclear Power Station curtailed power production 3 times in summer 2013 and again in August 2015 due to Cape Cod Bay water exceeding the 75°F NRC limit.[287] Droughts can have a similar impact on power production by reducing available cooling water supplies, and can contribute to wildfires that can threaten overhead infrastructure. The risk of wildfires increases when vegetation is very dry. Wildfires can damage EPS overhead infrastructure.

USGCRP projects that due to climate change, in the Northeast "the frequency, intensity, and duration of heat waves is expected to increase…. Seasonal drought risk is also projected to increase in summer and fall as higher temperatures lead to greater evaporation and earlier winter and spring snowmelt."[288]

Policy recommendation: OER could consider requiring or preferential scoring for microgrids that

[283] https://en.wikipedia.org/wiki/2011_Halloween_nor'easter
[284] https://en.wikipedia.org/wiki/January_1998_North_American_ice_storm
[285] USGCRP 2014, accessed at: http://nca2014.globalchange.gov/report/regions/northeast
[286] http://www.thehour.com/business/article/Feds-OK-higher-water-temperature-for-Millstone-8053731.php
[287] https://www.bostonglobe.com/metro/2015/08/11/high-water-temperatures-forced-power-cut-pilgrim-nuclear-plant/fMgG6VtRmadnVcuacbPpGI/story.html
[288] USGCRP 2014, accessed at: http://nca2014.globalchange.gov/report/regions/northeast

support water management facilities; incorporate measures for heat-mitigation (*e.g.*, temperature control for battery systems) or drought resistance (*e.g.*, low-/no-water use DERs); and that provide four-season mission-critical functionality such as continuity of operations or shelter in place. Geographic dispersion of microgrids could contribute to risk mitigation.

Geologic/Seismic – Earthquake, tsunami, volcano. The Northeast experiences earthquakes, although not with the frequency and magnitude of more seismically active areas such as the west coast. The largest earthquake recorded in Rhode Island in 1951 measured 4.6 on the Richter scale; the largest quakes in New England have been recorded or estimated to be in the 5.8–6.0 range, which can damage poorly constructed buildings and slightly damage well-constructed ones.[289] Earthquakes pose a greater hazard for natural gas pipelines than for overhead EPS infrastructure.

The RI State Interagency Hazard Mitigation Committee decided not to include volcanoes and tsunamis in the 2014 update to the RI Hazard Mitigation Plan, due to the "lack of frequency in which they occur; (t)he minimal probability of their occurrence; and / or (t)he lack of resources to devote any amount of time to further research the likelihood or potential occurrence or impact."[290]

The risk of tsunamis to the U.S. east coast is low, but they have occurred before; the authors consider this hazard to be a low-to-high-impact, very-low-frequency event. Scientists note the potential that a lateral collapse of the western flank of a volcano on La Palma island in the Azores during an eruption could trigger a large tsunami impact on the eastern seaboard.[291] A tsunami would be preceded by a warning period. Direct damage could range from minor to catastrophic depending on wave heights.

Volcanoes are not a proximate threat to Rhode Island; the authors consider this hazard to be a low-to-moderate-impact, very-low-frequency event. Severe global impacts have occurred in the geologic record, and less severe events with global effects have occurred in recent centuries such as the 1883 Krakatoa eruption. OER might consider the contingency that large remote eruptions could inject significant amounts of ash into the upper atmosphere, reducing global sunlight levels, reducing surface temperatures and potentially altering weather patterns. These effects could increase heating fuel demand and impact energy systems such as solar PV and wind turbines. Very severe events such as a "supervolcano" eruption in the Yellowstone caldera could precipitate ash that might interfere with the EPS and DERs.

<u>Policy recommendation</u>: OER could consider requiring or preferential scoring for seismic event mitigation in microgrid installations, for example against a Richter 6.0 event. Tsunami and volcano mitigation is not worth dedicated effort, due to low probability and the difficulty of determining hazard areas. Geographic dispersion of microgrids could contribute to risk mitigation.

[289] RIEAP,pp. 9-7 & 9-8; see also: http://nesec.org/earthquakes-hazards/
[290] RIEMA, *Rhode Island 2014 Hazard Mitigation Plan Update*, 2014, p. 35.
[291] https://www.washingtonpost.com/blogs/capital-weather-gang/post/could-a-tsunami-strike-the-us-east-coast/2011/03/14/ABIb9AV_blog.html?utm_term=.0e3ff7952cbf

Space weather – Solar flare / coronal mass ejection (CME) / geomagnetic disturbance (GMD). A solar flare or coronal mass ejection (CME) from the Sun is a regular occurrence. Satellites that monitor the sun and other techniques can provide an hour or more of early warning to enable utilities to take protective actions. If a large CME impacts Earth it can cause a significant, widespread geomagnetic disturbance (GMD) and resulting geomagnetically-induced currents (GIC) capable of damaging electrical equipment over a wide area. As NERC and DOE report: "Geomagnetically-induced currents on system infrastructure have the potential to result in widespread tripping of key transmission lines and irreversible physical damage to large transformers."[292] The EISC notes: "Historically, the frequency at which powerful CMEs have affected the earth is estimated as once per 100 – 200 years. The largest CME-event in relatively recent history, the 'Carrington Event,' occurred in 1859, followed 62 years later by another event of similar magnitude, the 1921 'Railroad Storm.' Although both events caused serious damage to the global telegraph network and the related systems that existed at those times, effects of similar storms on modern power grids would be incomparable."[293] "A similar-sized solar flare [to 1859] today would knock out electricity grids across entire continents. [A 2014] report from the US National Academy of Sciences estimated recovery would take years, and cost more than $ US2 trillion."[294]

In 2013 Federal Energy Regulatory Commission (FERC) Order 779 directed NERC "to submit to the Commission for approval proposed Reliability Standards that address the impact of geomagnetic disturbances (GMD) on the reliable operation of the Bulk-Power System…. The Second Stage GMD Reliability Standards must identify benchmark GMD events that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System. If the assessments identify potential impacts from benchmark GMD events, the Reliability Standards should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event."[295] RIEAP notes that energy industry stakeholders considered solar flare risks to be confined to the electricity sector, but not a risk to natural gas infrastructure.[296]

Policy recommendation: OER could consider requiring or providing preferential scoring for E-threat[297] mitigation measures in designated microgrids (*e.g.*, component shielding).[298] Geographic dispersion of microgrids could contribute to risk mitigation.

[292] NERC and DOE, *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*, 2010, p. 8.
[293] http://www.eiscouncil.com/BlackSky/Details/24
[294] https://cosmosmagazine.com/technology/early-warning-system-solar-flares
[295] https://www.ferc.gov/whats-new/comm-meet/2013/051613/E-5.pdf
[296] RIEAP, p. 3-5.
[297] EISC, *E-Pro Handbook*, 2014, p. ii, footnote #5.
[298] For example, see EISC, *E-Pro Handbook*, 2014, accessible at: http://www.eiscouncil.com/App_Data/Upload/3dadf58f-7457-46bf-92a4-551c6608d925.pdf

Pandemic. NERC and DOE report: "A pandemic is defined as a global outbreak of a new virus or disease with sustained and efficient human-to-human transmission. Generally little or no immunity exists to the disease and it causes illness and, in some cases, death. The severity and duration of pandemics vary significantly and will be difficult to predict, as each virus carries its own unique set of characteristics. Several pandemics occur each century…. Pandemic risk differs from many of the other threats facing the system in that it is a 'people event.' The principal vulnerability with respect to a pandemic is the loss of staff critical to operating the electric power system. Without these personnel, operational issues on the system would increase as less-trained or less-experienced individuals work to operate generation plants, address mechanical failures, restore power following outages caused by weather and other natural events, and operate the system…. Similar to other critical infrastructures, the day-to-day operation of the bulk power system is highly-dependent upon the availability of a uniquely-trained and specialized workforce. Significant reductions and impacts to that workforce could have serious and negative consequences for reliability, as it can be assumed that sector employees will be just as vulnerable to the disease as the general public, absent any intervening measures. A severe pandemic could result in workforce impacts that could endure for weeks or even months."[299] There is a small but growing risk of man-made pandemics that could be caused by bioterrorism or industrial accidents.

In a sense, pandemic risk reflects aging in critical assets: utility employees. One observer noted in 2012: "The average U.S. utility worker is close to 50 years old, according to the Bureau of Labor Statistics. The Center for Energy Workforce Development -- a nonprofit consortium of electric, natural gas and nuclear utilities -- estimates that about 40 percent of the nation's energy workers will be retiring or otherwise leaving the industry by 2015. More than three out of five line superintendents -- the most experienced workers, who manage the construction, operation, maintenance and repair of electrical distribution lines -- are age 50 or older, according to a study by the National Rural Electric Cooperative Association."[300] Streamlined workforces leave many utilities with a 'thin bench" of skilled personnel. A pandemic could be a stressor on all sectors of society, hindering response to a coincident crisis.

<u>Policy recommendation</u>: Microgrids that support emergency response, mass care, or shelter in place could provide significant value during pandemics, when public health functions are critical and staying home might be mandated or otherwise contribute to mitigating disease spread.

<u>Manmade hazards</u>

Aging infrastructure, equipment failure. Equipment failures can stress the EPS, but the system has significant redundancy and resiliency to single-unit-loss contingencies. Regionally, "ISO-

[299] NERC and DOE, *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*, 2010, p. 11, 47.

[300] http://www.newsday.com/opinion/oped/need-for-utility-workers-is-a-problem-and-an-opportunity-jennifer-wheary-1.4226041

NE operates the bulk electricity grid under a series of layered contingency plans so that the loss of one (1) or more generators or transmission lines will not significantly affect reliability across the grid."[301] Although RI is part of the regional EPS network, in-state generation capacity can serve most but not all peak day load, and transmission capacity linking to out of state resources is constrained. National Grid manages these risks with annual budgets for planned and unplanned equipment maintenance and replacement.[302]

In-state power generation is almost entirely dependent on natural gas, although a few larger power stations have dual-fuel capability. The supply network can withstand the loss of up to two natural gas pipeline compressor stations without curtailments in the short run to power production. Complete failure of a natural gas transmission pipeline on a peak demand day could result in curtailments, although National Grid maintains up to 13 days of supplemental LNG storage to provide a buffer.[303]

<u>Policy recommendation</u>: Microgrids could help mitigate pandemic risk. OER could consider preferential scoring for renewable energy (RE) DERs which reduce reliance on fuel supplies that are subject to critical infrastructure disruptions (although intermittent RE sources also feature low average availability factors). Geographic dispersion of microgrids could contribute to risk mitigation.

Human error, accidents. With reference to RIEAP/RIHMP hazard classifications, "human" error and accidents could have similar impacts on the EPS as "technical" equipment failures, but lack the typical warning indicators associated with equipment maintenance and capital asset assessments. "Normal Accident" theory describes the inevitability of failures in complex technological systems due to organizational behavior factors; challenges to operator understanding of opaque, rapid and synergistic component interactions and system dynamics in real time; and other considerations.[304] This theory suggests that "human"-influenced accidents could potentially be more severe than "technological" equipment failures. For example, operator interventions can accidentally or intentionally circumvent safety features or otherwise worsen technical systems' failure modes (*e.g.*, Three Mile Island in 1979, Piper Alpha in 1988, Chernobyl in 1989). In addition to EPS or natural gas system "human" accidents, industrial or transport accidents could impact EPS functionality.

<u>Policy recommendation</u>: Microgrids could be considered a risk mitigation strategy for this set of hazards. OER could consider preferential scoring for renewable energy (RE) DERs which reduce reliance on fuel supplies that are subject to critical infrastructure disruptions (although intermittent RE sources have low average availability factors). Geographic dispersion of microgrids could contribute to risk mitigation.

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[301] RIEAP, p. 6-17.
[302] For example, see National Grid, *Electric Infrastructure, Safety and Reliability Plan FY2017 Proposal*, 2015, at: http://www.ripuc.org/eventsactions/docket/4592-NGrid-Electric-ISR-FY2017_12-9-15.pdf
[303] RIEAP, p. 9-13.
[304] See Charles Perrow, *Normal Accidents: Living with High-Risk Technologies*, 1984, and https://en.wikipedia.org/wiki/Normal_Accidents

Physical attack. The EPS has long experience with ongoing vandalism and sabotage, generally with relatively localized effects and minor impacts on system functionality. Coordinated physical or kinetic attacks on the EPS pose unique risks of "black sky" outage events via targeted destruction of critical infrastructure with long replacement lead times (*e.g.,* Extra High Voltage transformers), particularly at multiple locations. Readily available weapons such as firearms and Improvised Explosive Devices (IEDs) can severely damage or destroy vital EPS equipment. Physical security measures can mitigate risks, although they can be overcome by determined adversaries.

In April 2013 in California, unidentified attackers fired rifles at Pacific Gas & Electric's (PG&E's) Metcalf Substation from outside the fence and security camera coverage, causing $15 million in disabling damage to 17 out of 23 transformers that took 27 days to repair. Former FERC Chairman Jon Wellinghoff described the attack as "the most significant incident of domestic terrorism involving the grid that has ever occurred". In 2014 FERC mandated physical security standards for substations.[305]

<u>Policy recommendation</u>: OER could consider requiring or providing preferential scoring for physical protection measures in designated microgrids. OER could consider preferential scoring for renewable energy (RE) DERs which reduce reliance on fuel supplies that are subject to critical infrastructure disruptions (although intermittent RE sources have low average availability factors). Geographic dispersion of microgrids could contribute to risk mitigation, although well-informed determined adversaries could counteract this protective strategy.

Cyberattack. The EPS is vulnerable to disruption through intentional attack over the internet, due to the interconnections of organizational computers, networked devices, and systems' Supervisory, Control and Data Acquisition (SCADA) software programs. It is possible for cyberattacks to physically destroy EPS critical infrastructure such as generators and transformers; coordinated physical and cyberattacks pose greater black sky hazards. State and non-state "hackers" probe and assault EPS systems thousands of times each day. The Department of Homeland Security's Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) reported responding to 256 cyber incidents in 2013, with over half targeting the energy sector.[306] The electricity industry and government organizations cooperate on cyber protection, *e.g.,* via information sharing and FERC and NERC's Critical Infrastructure Protection (CIP) Version 5 cybersecurity standards. The threat is constantly evolving along with protective measures; experts agree that the offense has an advantage over the defense in this dynamic. The Department of Defense (DoD) is motivated to develop critical facility microgrids in large part as a response to the cyber threat to the civilian EPS, upon which DoD facilities are almost entirely dependent.

[305] https://en.wikipedia.org/wiki/Metcalf_sniper_attack
[306] http://www.eiscouncil.com/BlackSky/Details/21

Policy recommendation: OER could consider requiring or providing preferential scoring for cyber security measures in designated microgrids, *e.g.*, equipment controls "air gapping" with no connection to the Internet, or application of the National Institute for Standards and Technology (NIST) Cybersecurity Framework (CSF) and related standards.[307] Geographic dispersion of microgrids could contribute to risk mitigation, although well-informed determined adversaries could counteract this protective strategy.

Intentional Electromagnetic Interference (IEMI) attack. Non-nuclear IEMI weapons are being developed by many states and companies; some can be assembled by non-state actors with commercial off-the-shelf (COTS) components. "The pulse from… (IEMI) devices can be far higher in magnitude and frequency than EMP, though its effective range is far shorter, affecting only discrete "point" targets. When manufactured as weapons, IEMI devices, also known as Radio Frequency (RF) weapons, can in some cases produce multiple, repeated pulses, and are typically quite mobile…. This hazard has been characterized as a "dumb" cyber threat, as the assets most vulnerable are computers and electronics. IEMI weapons can damage or destroy microprocessors, corrupt or wipe out data on hard drives, and could cause misoperation of relays and electrical arcing in high power system components such as transformers."[308]

Policy recommendation: OER could consider requiring or providing preferential scoring for E-threat mitigation measures in designated microgrids (*e.g.*, component shielding).[309] Geographic dispersion of microgrids could contribute to risk mitigation, although well-informed determined adversaries could counteract this protective strategy.

Nuclear weapons - Electromagnetic Pulse (EMP) attack. The U.S., Britain, China, France, India, Israel, Russia, North Korea and Pakistan have nuclear weapons. Non-state actors such as terrorists could acquire or develop crude weapons comparable to the those used on Hiroshima and Nagasaki—a technological achievement that is more than seventy years old. "A nuclear detonation in the upper atmosphere creates an electromagnetic pulse (EMP), a powerful, damaging electromagnetic field covering a subcontinent-scale region." EMP effects differ from the direct heat, blast and radiation effects of a nuclear weapon; high-altitude detonations might not be seen or heard by those impacted by EMP at ground level. A high-altitude nuclear explosion radiates EMP energies from the detonation point to the visible horizon and can extend for thousands of miles depending on the blast altitude (*e.g.*, 15–300 miles above the earth). There are two pulse components of greatest concern, labeled E1 and E3. The E1 pulse is very fast (<1 microsecond) and intense and can induce very high voltages in electrical conductors that can damage unprotected electronics. The E3 pulse is slower (tens to hundreds of seconds) and can cause a geomagnetic disturbance (GMD) and ground-induced current (GIC) similar in effect to a solar flare.

In an EMP event, "most conventional computers and low voltage electronics will likely be unaffected and available to be reenergized if power grid operation can be restored – a key factor

[307] https://www.nist.gov/sites/default/files/documents/cyberframework/cybersecurity-framework-021214.pdf and http://nvlpubs.nist.gov/nistpubs/Legacy/SP/nistspecialpublication800-39.pdf
[308] http://www.eiscouncil.com/BlackSky/Details/20
[309] EISC, *E-Pro Handbook*, 2014, p. ii, footnote #5.

in enabling cost effective power grid protection strategies – and in preserving the viability of most of the customer "load" that will also be essential to such strategies.… [A]n EMP strike on an unprotected power grid, especially given its large, multi-region footprint, would cause an extended duration, subcontinent-scale duration power outage, and would precipitate cascading, direct and indirect failures of all other critical societal infrastructures."[310] Note that even worst-case-scenario nuclear power station failures could not produce nuclear explosions or significant EMP effects.

Policy recommendation: OER could consider requiring or providing preferential scoring for E-threat mitigation measures in designated microgrids (*e.g.*, component shielding).[311] Geographic dispersion of microgrids could contribute to risk mitigation.

Nuclear weapons – war, terrorism, dirty bombs. The U.S., Britain, China, France, India, Israel, Russia, North Korea and Pakistan have nuclear weapons. Non-state actors such as terrorists could devise radiological "dirty bombs" with little difficulty, and with more difficulty might acquire or develop crude fission weapons comparable to the those used on Hiroshima and Nagasaki—a technological achievement that is more than seventy years old.

Nuclear weapons release immense amounts of energy in the form of blast, heat and radiation. (Note that even worst-case-scenario nuclear power station failures could not produce nuclear explosions or significant EMP effects.) In wartime, adversary states would probably launch several to very many nuclear weapons aimed at ground level for hardened or subterranean targets; low-altitude airbursts with a larger damage radius for cities or softer targets; and high-altitude detonations for maximum EMP effects (but not blast effects). Non-state actors such as terrorist organizations would more probably detonate one or a small number of nuclear weapons at ground level or low altitude, due to the technical challenges of developing nuclear weapons (although they could be acquired) and of delivering them to high altitudes.

A Hiroshima- or Nagasaki-equivalent 10–20 kiloton nuclear explosion at ground level or low altitude (*e.g.*, from a terrorist attack) could cause devastation or severe damage at a radius of ~1 mile; moderate damage out to ~2 miles; and light damage ~5 miles away, as well as produce a plume of radioactive fallout with farther-reaching impacts.[312] It could cause relatively localized EMP E1 and E3 effects extending to a radius of ~5–10 miles.[313]

Although the risk of a nuclear war involving the U.S. is relatively low, more probable nuclear wars in other parts of the world could impact the Americas. Research indicates that the detonation of 100 Hiroshima-sized nuclear weapons on cities anywhere in the world could inject large quantities of smoke into the upper atmosphere, reducing sunlight reaching the Earth's surface and causing nuclear winter-type effects for up to 10 years that could cripple global

[310] http://www.eiscouncil.com/BlackSky/Details/19 and https://en.wikipedia.org/wiki/Nuclear_electromagnetic_pulse
[311] EISC, *E-Pro Handbook*, 2014, p. ii, footnote #5.
[312] https://en.wikipedia.org/wiki/Effects_of_nuclear_explosions
[313] http://www.globalsecurity.org/wmd/library/policy/army/fm/3-3-1_2/Appc.htm

agriculture and threaten at least 1 billion people with starvation.[314] These effects could increase heating fuel demand and impact energy systems such as solar PV and wind turbines.

The U.S., Britain, China, France, Russia, and probably India, Israel and Pakistan each have enough nuclear weapons to produce these climatic results. The risk of nuclear conflict somewhere on Earth with global consequences is probably higher now than during the Cold War. Unlike the U.S. and the Soviet Union, India and Pakistan are hostile neighbors with no "strategic space" to allow much time for decision makers to assess and respond to perceived missile attacks that could be nuclear; they fought major wars in 1948, 1965 and 1971 and continue low-grade armed conflict via border clashes and state-sponsored terrorism; reportedly neither side maintains communications "hot lines" with their adversary counterparts for prompt crisis management; and both sides are deploying nuclear weapons at sea in dual-use nuclear-or-conventional delivery systems that increase the risk of intentional or accidental nuclear war.

"Dirty bombs" are radiological weapons that do not explode with significant force, but can contaminate a local area with radioactive particles sufficient to render it effectively uninhabitable and require an immensely expensive clean-up effort. Radioactive materials that could be used to produce a dirty bomb are accessible in numerous civilian applications such as health care, industrial and research facilities. Development and use of these weapons is probably exclusively in the realm of non-state actors. Such an attack probably would not kill many people directly and would have relatively localized physical effects, but the psychological and economic impacts could be significant.

Policy recommendation: OER could consider requiring or providing preferential scoring for E-threat mitigation measures in designated microgrids (*e.g.*, component shielding). Microgrids that support emergency response, mass care, or shelter in place could provide significant value during nuclear incidents, when public health functions are critical and staying home might be mandated or otherwise contribute to mitigating fallout impacts.[315] Not much can be done to mitigate the proximate effects of nuclear explosions on microgrids. Geographic dispersion of microgrids could contribute to risk mitigation.

[314] http://climate.envsci.rutgers.edu/pdf/RobockToonSciAmJan2010.pdf

[315] EISC, *E-Pro Handbook*, 2014, p. ii, footnote #5.

APPENDIX B: NATIONAL GRID HAZARD RESPONSE AND HISTORICAL RELIABILITY

National Grid is the electricity distribution company (EDC) serving ~99% of RI customers.[316] The RIEAP states: "National Grid's system contains a considerable amount of redundancy and system protection to minimize the impact of events to its customers. System protection is comprised of numerous devices and schemes (*e.g.*, relays, breakers, reclosers, fuses, under-frequency load shedding, over-frequency generator shedding, turbine vibration controls, governors)…. National Grid's electric system is reported to be designed to withstand the loss of any single high voltage element (*e.g.*, transmission lines, transformers or power plants) without any impact to customers, which is compliant with NERC standards."[317] National Grid also is the state's only natural gas Local Distribution Company (LDC) and maintains redundant pipeline and storage capacity for system reliability and resilience, including for RI's power generation which is almost entirely dependent on natural gas supply.[318]

Despite best practices, any EDC is vulnerable to hazards that can cause prolonged outages. Severe weather events and other natural and man-made disasters pose challenges that are almost impossible for grid operators to overcome. See Introduction and Appendix A for further discussion.

National Grid reports annually on its reliability using metrics including System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). "SAIDI quantifies the total number of minutes (duration of events) that an average customer would be without electricity during a given year, and SAIFI quantifies the total number of times (frequency of events) that an average customer would be without electricity during a given year."[319]

Both SAIDI and SAIFI are calculated with and without the inclusion of Major Event Days (MEDs). National Grid defines MEDs as: "A Major Event Day (MED) is defined as a day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a MED threshold

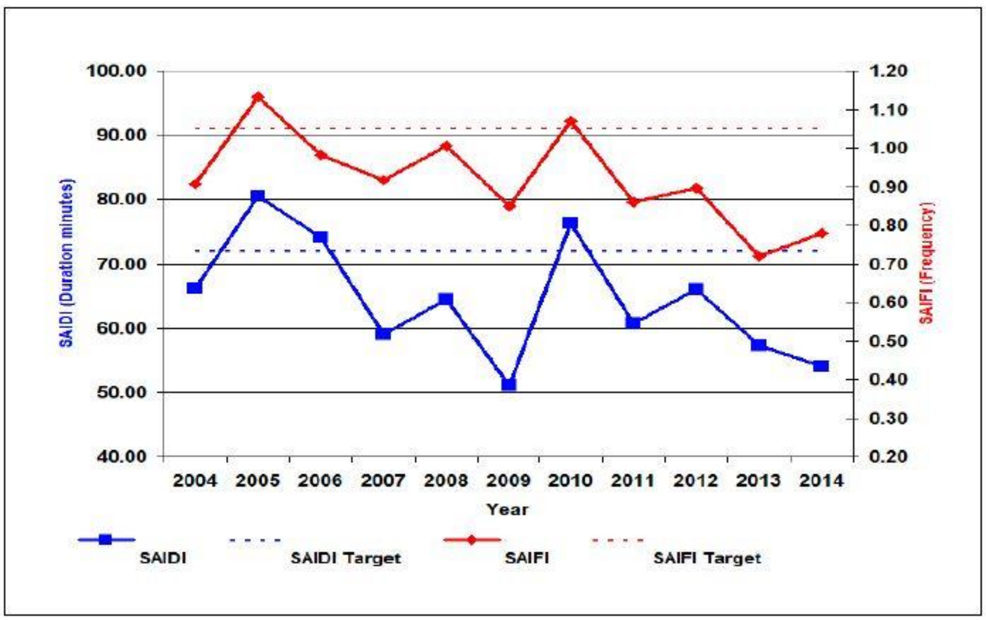
[316] From National Grid, *Electric Infrastructure, Safety and Reliability (ISR) Plan FY2017 Proposal*, p.26: "[National Grid] delivers electricity to 486,465 Rhode Island customers in a service area that encompasses approximately 1,076 square miles in 38 … cities and towns. To provide this service, the Company owns and maintains 5,225 miles of overhead and 1,103 miles of underground distribution and sub-transmission circuit in a network that includes 94 sub-transmission lines and 390 distribution feeders. The Company relies on 66 distribution substations that house 134 power transformers and 823 substation circuit breakers to deliver power to its customers. The Company's electric delivery assets also include 280,612 distribution poles, 4,252 manholes, and 77,540 overhead (pole-mounted) and underground (pad-mounted or in vault) transformers."

[317] RIEAP, p.9-8.
[318] RIEAP, p. ES-7.
[319] RIEAP, pp.9-8–9.9.

value (5.64 minutes for 2014). For purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than the MED are days on which the energy delivery system experiences stress beyond that normally expected, such as during severe weather."[320] MEDs impose the greatest challenges to critical facilities and the communities that depend on them, especially multi-day outages; these contingencies are where microgrids can provide the greatest value.

Below are depictions of SAIDI and SAIFI for 2004–2014, first without MEDs:

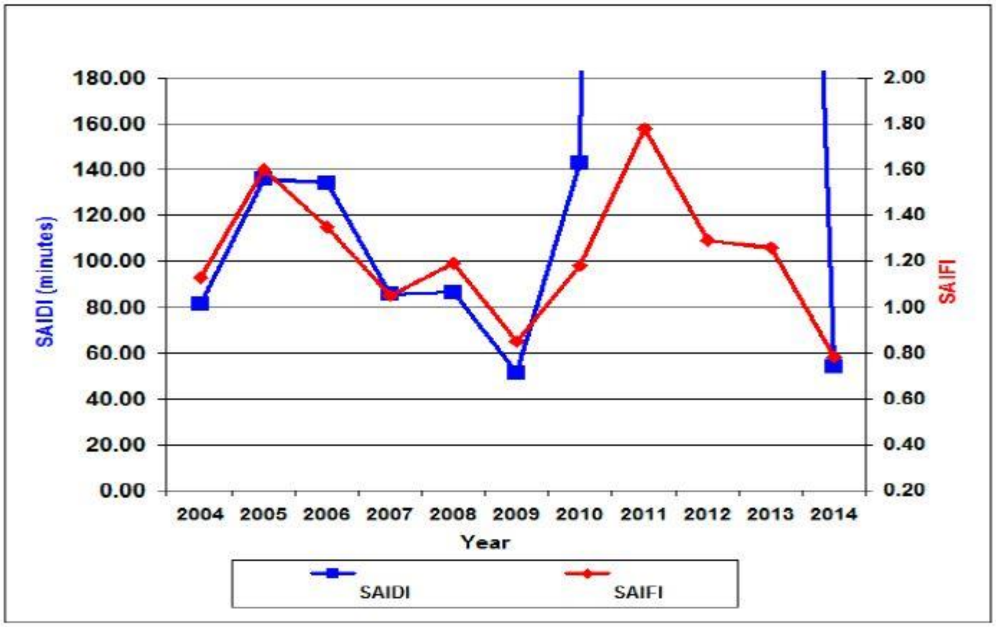
Chart 1a
RI Reliability Performance
Regulatory Criteria (Excluding Major Event Days)



For comparison, consider the impact of including MEDs on these calculations, notably during 2011–2013 when there were several severe weather events (in 2014 National Grid reported no MEDs):

[320] National Grid, *Electric Infrastructure, Safety and Reliability (ISR) Plan FY2017 Proposal*, p. 26.

Chart 1b
RI Reliability Performance
Regulatory Criteria (Including Major Event Days)



A review of outage causes from this same period illustrates the impact of MEDs on customer outage assessments. Charts 2 and 2a depict customer interruptions by cause, without including MEDs:

Chart 2
Rhode Island Customer Interrupted by Cause
Major Event Days Excluded
By Calendar Year (2008-2014)

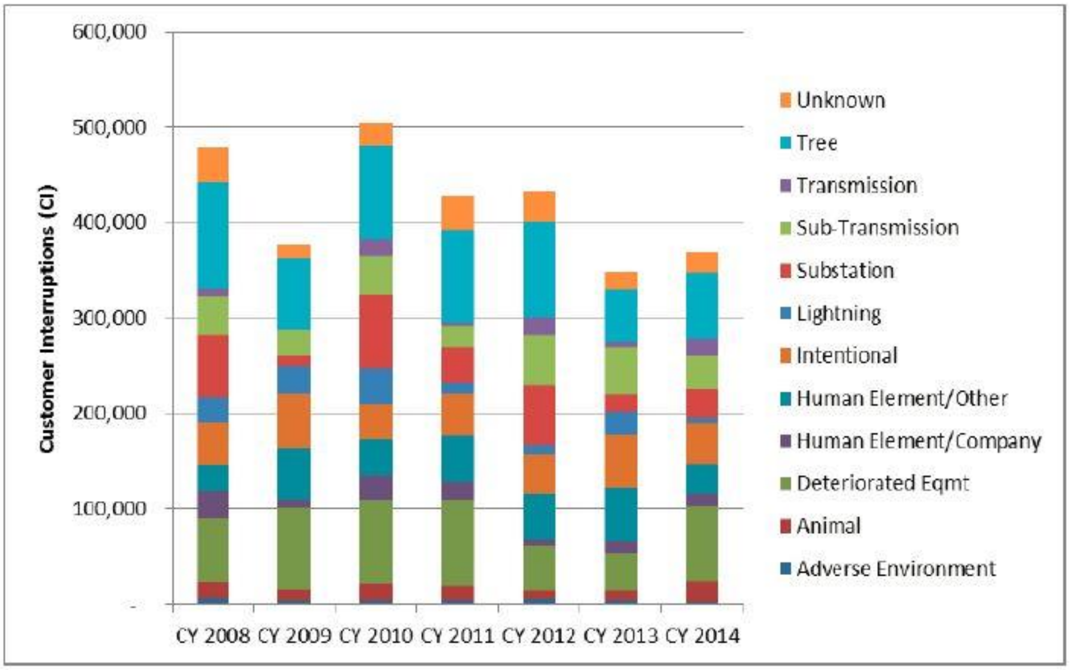


Chart 2A
Rhode Island Customer Interrupted by Cause
Major Event Days Excluded
By Calendar Year (2008-2014)

Cause	CY 2008	CY 2009	CY 2010	CY 2011	CY 2012	CY 2013	CY 2014
Adverse Environment	5,910	3,926	3,800	4,444	4,778	4,318	3,220
Animal	16,977	11,769	18,021	15,547	9,912	10,324	21,247
Deteriorated Equipment	67,114	85,047	87,768	89,743	47,301	39,131	79,260
Human Element/Company	28,298	8,450	26,047	18,455	7,043	13,481	13,259
Human Element/Other	27,607	54,275	36,999	48,650	47,404	54,719	29,908
Intentional	44,887	58,356	37,743	44,526	40,927	55,927	43,132
Lightning	25,987	27,874	36,859	11,044	9,362	23,310	5,745
Substation	65,704	10,713	77,189	37,086	63,397	18,882	30,888
Sub-Transmission	40,845	28,046	40,034	22,524	51,972	48,902	33,556
Transmission	8,721	25	18,438	2,973	19,099	5,958	18,284
Tree	109,214	74,116	97,807	97,485	100,459	55,056	70,277
Unknown	37,501	13,545	23,962	36,065	32,176	19,008	19,657
Grand Total	**478,765**	**376,142**	**504,667**	**428,542**	**433,830**	**349,016**	**368,433**

Charts 3 and 3a depict customer interruptions by cause, including MEDs:

Chart 3
Rhode Island Customer Interrupted by Cause
Major Event Days Included
By Calendar Year (2008-2014)

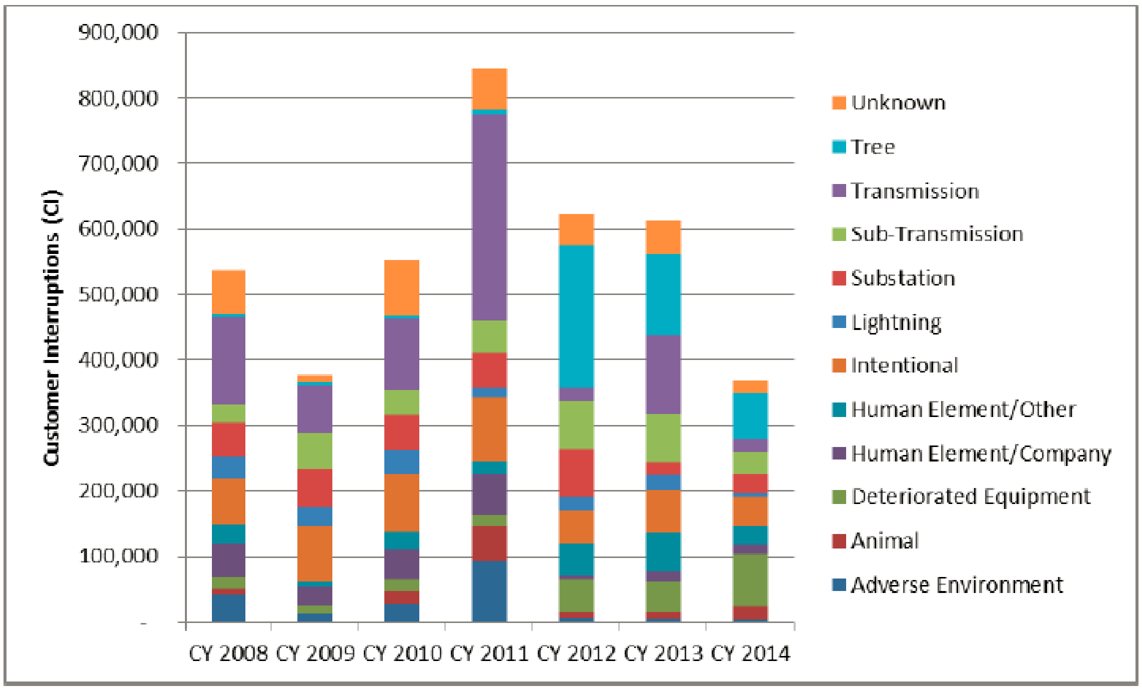


Chart 3A
Rhode Island Customer Interrupted by Cause
Major Event Days Included
By Calendar Year (2008-2014)

Cause	CY 2008	CY 2009	CY 2010	CY 2011	CY 2012	CY 2013	CY 2014
Adverse Environment	41,843	13,545	28,101	93,160	5,416	4,486	3,220
Animal	8,721	25	18,438	52,795	9,912	10,326	21,247
Deteriorated Equipment	16,977	11,769	18,031	15,952	48,891	46,390	79,260
Human Element/Company	51,279	28,046	46,082	63,381	7,335	15,549	13,259
Human Element/Other	28,298	8,450	26,067	20,423	47,404	58,321	29,908
Intentional	71,485	85,047	88,643	97,210	49,950	66,252	43,132
Lightning	34,386	27,874	36,859	15,111	21,002	23,310	5,745
Substation	51,720	58,356	54,349	51,741	74,256	18,882	30,888
Sub-Transmission	27,616	54,275	36,999	50,780	74,296	74,786	33,556
Transmission	132,780	74,116	107,610	314,416	19,112	119,638	18,284
Tree	5,926	3,926	5,303	5,569	217,931	122,661	70,277
Unknown	65,718	10,713	86,482	64,889	45,626	52,953	19,657
Grand Total	**536,749**	**376,142**	**552,964**	**845,427**	**621,131**	**613,554**	**368,433**

This data suggests that microgrids can significantly benefit customers during prolonged outages. The impact of longer-duration blackouts is notable in a comparison of outage metrics both with and without MEDs during three recent years with significant severe weather events. We will consider only those customer interruptions attributed to trees, transmission, sub-transmission and substation causes, as a very approximate correlation of outages with typical severe weather impacts on EPS overhead infrastructure (*e.g.*, wind-felled trees and blown debris that damage wires). In 2011 (*e.g.*, the year of Hurricane Irene and Storm Alfred), total customer interruptions increased ~164% when MEDs are included, from ~160,000 to ~422,500. In 2012 (*e.g.*, Superstorm Sandy) customer interruptions including MEDs were 64% higher, and in 2013 (*e.g.*, Storm Nemo) interruptions were 161% higher.

This very general high-level comparison is at best a very rough indicator of correlation, without sufficient detail to establish causation between the named storm events and interruption data. Yet critical facility microgrids could provide the greatest benefit to customers and communities during longer-duration outages, and are less susceptible to severe weather disruptions than is the EPS if only due to reduced reliance on vulnerable transmission and distribution networks. Microgrids comprising small numbers of critical facilities could not much reduce the numbers of customer interruptions, but they could significantly reduce suffering and improve public health and safety for large numbers of customers by maintaining critical services and safe havens during prolonged outages.

APPENDIX C: CRITICAL FACILITY DESIGNATIONS BY STATE MICROGRID PROGRAMS, USDHS, AND PEMA, AND REPRESENTATIVE RIGIS DATABASE INFORMATION

Table AC-1 lists the types of critical facilities considered eligible by state microgrid programs in California, Connecticut, Massachusetts, New Jersey and New York.

Table AC-1: State microgrid program critical facility designations

CA	CT	MA	NJ	NY
▪ Hospitals ▪ Emergency operation centers ▪ Care facilities ▪ Fire stations ▪ Police stations ▪ Water treatment facilities ▪ Wastewater treatment facilities ▪ Facilities identified as sources of essential services in California Local Energy Assurance Plan (CaLEAP) ▪ Fueling facilities ▪ Ports ▪ Critical federal, state, municipal facilities (*e.g.* courts and jails) ▪ Schools ▪ Shelters (provide shelter to humans and/or animals during a public emergency) ▪ Supermarkets	▪ Hospital ▪ Police station ▪ Fire station ▪ Water treatment plant ▪ Sewage treatment plant ▪ Public shelter ▪ Correctional facility ▪ Commercial area of municipality ▪ Municipal center ▪ Other facility identified by chief elected authority of municipality as critical ▪ Other facility/area identified by DOE as critical ▪ Other facility/area identified by EPA as critical	<u>Life Safety Resources:</u> ▪ Police station ▪ Fire station ▪ Hospital ▪ Water treatment ▪ Wastewater treatment ▪ Emergency communications ▪ Emergency Shelters <u>Lifeline Resources:</u> ▪ Food supply ▪ Fuel supply ▪ Transportation facilities ▪ Transportation resources <u>Community Resources:</u> ▪ City/town hall ▪ Senior center ▪ School capable of acting as shelter ▪ Multi-family housing capable of acting as shelter	▪ Wastewater treatment facilities ▪ Water treatment facilities ▪ Long term care facilities ▪ Colleges and universities ▪ Primary and secondary schools that act as shelters, other facilities that act as shelters during disasters ▪ Multifamily housing units ▪ Transport and transit infrastructure ▪ Prisons ▪ Police departments ▪ Public safety answering points (PSAPS) ▪ Certain municipal building and town centers ▪ Other Tier 1 and Tier 2 CF	▪ Wastewater treatment plan ▪ Hospitals ▪ Universities ▪ Facility of refuge/shelter ▪ Schools (K-12) ▪ Police departments ▪ Libraries ▪ Fire stations

Table AC-2 lists the types critical facility designations used by U.S. Department of Homeland Security (USDHS), the Rhode Island Emergency Management Agency (RIEMA), and the City of Providence, RI Emergency Management Agency (PEMA). It also depicts data available in Rhode Island Geographic Information System (RIGIS) layers.

Table AC-1: State microgrid program critical facility designations

From USDHS, Adopted by RIEMA	From PEMA (Providence Emergency Management Agency)	RIGIS data available
▪ Agriculture and Food	▪ Agriculture and Food	▪ Town and city halls
▪ Defense Industrial Base	▪ Defense Industrial Base	▪ State facilities
▪ Energy	▪ Energy	▪ E-911 sites
▪ Healthcare and Public Health	▪ Healthcare and Public Health	▪ Ports and commercial harbors
	▪ National Monuments and Icons	▪ Marinas
		▪ Libraries
▪ Financial Services	▪ Banking and Finance	▪ Law enforcement
▪ Water & Wastewater	▪ Water	▪ Hospitals
▪ Chemical	▪ Chemical	▪ Fire stations
▪ Commercial Facilities	▪ Commercial Facilities	▪ EMS
▪ Critical Manufacturing	▪ Critical Manufacturing	▪ Dams
▪ Dams	▪ Dams	▪ Correctional institutions
▪ Emergency Services	▪ Emergency Services	▪ Airports
▪ Nuclear Reactors, Materials, Waste	▪ Nuclear Reactors, Materials, Waste	▪ Active solid waste facilities
		▪ Colleges and universities
▪ Information Technology	▪ Information Technology	▪ Navigational lights
▪ Communications	▪ Communications	▪ Navigational buoys
	▪ Postal and Shipping	▪ Navigational beacons
▪ Transportation Systems	▪ Transportation Systems	▪ Hardened shorelines in Narragansett Bay
▪ Government Facilities	▪ Government Facilities	
		▪ Coastal barriers
		▪ Breakwaters

APPENDIX D: RECOMMENDED POLICIES

Below is a compilation of recommended policies, organized by section.

PART A: CRITICAL FACILITIES

A2 Critical facility prioritization: OER could require facilities that apply for microgrid program funding to complete a RIEMA Critical Infrastructure Assessment Tool (CIAT) survey. The survey's energy-related questions could be expanded to collect additional energy assurance information such as annual energy use and cost; critical loads including mission-critical energy-using systems and HVAC systems type; BUG characteristics (*e.g.*, size or fuel type, or presence of additional onsite distributed energy resources (*e.g.*, solar photovoltaics or combined heat and power systems). Microgrid funding applications could also collect this type of information.

A2 Critical facility prioritization: OER should use the Point Scoring method to simplify the process and conserve program and project resources. This authors suggest a scoring template in Table C-1, which OER can modify as desired. If OER chooses to use the Economic valuation method, OER should provide a detailed template and guidance for applicants to apply the appropriate conversion factors to their project, and/or support applicant CBA with funding or technical assistance teams.

A2 Critical facility prioritization: OER could have a two-track approach to identifying and prioritizing critical facilities in a microgrid program: a bottom-up "Public Track" and a top-down "Unique Asset" track.

A2 Critical facility prioritization: OER could prioritize energy assurance for private sector facilities that enable service restoration for the EPS, natural gas and other critical infrastructure networks.

A3.1 Electricity dependency on natural gas: OER could consider requiring natural gas fueled microgrids to secure firm supply contracts.

A3.2 Liquid fuels supply chain resilience: OER could prioritize petroleum marine terminals and storage facilities for microgrid support, *e.g.*, by preferential scoring and/or including them in a Unique Asset Track.

A3.2 Liquid fuels supply chain resilience: OER could prioritize service stations for microgrid support, *e.g.*, by preferential scoring and/or including them in a Unique Asset Track focused exclusively on gas stations.

PART B: MICROGRID TECHNOLOGIES AND APPLICATIONS

B4.3 Controls: OER could consider requiring or providing preferential scoring for microgrid projects to use the Duke COW interoperability standards.[321]

B4.3 Controls: OER could consider requiring or providing preferential scoring for microgrid project testing of their control schemes with a real-time hardware-in-the-loop (HIL) test platform[322], such as that developed by MIT-Lincoln Lab's Erik Limpaecher and team. MIT-LL has offered to test microgrid controllers with their HIL testbed system that enters microgrid DER data and simulates DER performance to test the connected controller. MIT-LL could perform this service for a modest fee, and ideally access to microgrid performance data. Oak Ridge National Laboratory has also offered a similar service. Tested validation of microgrid design could reduce risk and increase stakeholder confidence in a microgrid development, particularly for larger and more complex microgrids with multiple DERs.

PART C: COST/BENEFIT ANALYSIS OF CRITICAL INFRASTRUCTURE MICROGRIDS

C1 Development of a microgrid cost-benefit analysis (CBA) framework: An OER microgrid program could develop a tool similar to (but more refined than) the author's spreadsheet-based CBAM tool, complemented by the Point Scoring method to simplify the process and conserve program and project resources. The authors suggest a scoring template in Table C-1, which OER can modify as desired.

C1 Development of a microgrid CBA framework: If OER prefers to use the Economic Evaluation method, the program should use the NY Prize CBA template, and where applicable modify the conversion factors to use Docket 4600 or other state-specific approaches. OER should provide applicants with a detailed CBA template and instructions, as well as feasibility analysis funding and/or technical support sufficient to the task.

C2.3 Using the CBAM tool to determine potential funding awards: OER should use the Eligible Equipment method to simplify program administration and foster consistency and equity in funding awards. Eligible Equipment grants should exclude generation, but include energy storage and electrical infrastructure. Reference the CT microgrid program electrical equipment list,[323] but make eligible facility internal rewiring to enable critical load circuit modifications and load shedding. OER should consider also providing applicants with the option to request Capital Contribution and Credit Enhancement awards, which would be evaluated on an equivalent basis with Eligible Equipment applications (*e.g.*, dollars per project or $/kW of DER capacity). This would provide an incentive to applicants to leverage non-program funds such as private investment, because smaller grant requests would be assessed more favorably.

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[321] https://www.duke-energy.com/our-company/about-us/smart-grid/coalition

[322] http://info.typhoon-hil.com/microgrid-controller-testbed-demo-using-hardware-in-the-loop

[323] See list in CT DEEP *Final Round 3 Application Instructions*, Part E-1, pp. 9–10, accessed at: http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/69dc4ebaa1ebe96285257ed70064d53c?OpenDocument

PART D: MICROGRID PROGRAM AND POLICY RECOMMENDATIONS

D1 Microgrid policies and programs in other jurisdictions: Many of the more complex successful microgrids were built in phases, such as the University of California - San Diego campus microgrid.[324] OER should take the same approach and develop microgrid programs and policies in phases. The first phase is a program aimed at helping public agencies and others conduct feasibility assessments of the potential for Level 1 single facility and Level 2 campus critical facility microgrids, with a competitive solicitation to identify and fund promising projects. The second phase could evaluate the pros and cons of potential pathways to development of Level 3 multi-user community microgrids. See section D2.2 for further discussion.

D2.1 Principles to inform policy goals of program design: The 2015 *Rhode Island Thermal Working Group Report* developed an excellent set of ten principles that are broadly applicable to other energy programs, including microgrids. [325] The following principles of program design are drawn from lessons learned by administrators of similar microgrid programs in other states, as well as other energy programs and general programmatic management best practices.

- Design the program carefully with a multi-stakeholder team before roll out.
- Employ an integrative design approach with the participation of key stakeholders from inception through implementation.
- Take an all-hazards approach.
- Seek alignment with existing objectives: emergency plans, GHG goals, energy programs, etc. Build on past accomplishments, current programs and efforts underway.
- Prioritize public and community benefits, with a focus on support for local and state public agencies.
- Prioritize protection of vulnerable populations: LMI, medically dependent, elderly, prisoners, etc.
- Deploy program funds cost-effectively by leveraging market forces, private investment and existing programs.
- Educate the marketplace with proactive outreach, template documentation and program transparency.
- Make the program as user-friendly as possible, yet detailed enough to foster successful project design.
- Enable microgrid host/owner an optimum degree of choice and foster market flexibility and creativity in microgrid development.

[324] https://building-microgrid.lbl.gov/ucsd
[325] See 2015 *Rhode Island Thermal Working Group Report*, pp. 13–14, at: http://www.energy.ri.gov/documents/Efficiency/Rhode_Island_Thermal_Working_Group_Report.pdf

Section D2.2 The Biggest Policy Decision: What (if any) changes to regulatory regime and role of EDC and/or third party market actors in MG development does OER want to pursue? The biggest questions relate to potential reshaping of the EDC business model by allowing it to do things it does not or cannot currently do, and/or by allowing non-utility entities to do things that are currently exclusively EDC functions or to compete directly with EDCs for service provision. The authors recommend that significant modifications to the regulatory regime should not be undertaken for microgrid program development alone, in isolation from more comprehensive consideration. If Rhode Island wishes to revisit and re-imagine fundamental aspects of the EPS and the role of the EDC, the authors recommend that effort should be allowed the time and resources to develop a comprehensive, thoughtful, multi-stakeholder consultative process.

Section 2.3 Administrative program measures: See this section for further discussion. Actions that OER could undertake under current conditions include:

- Provide program funding to assist with MG development at program & project level.
- Develop multi-stakeholder inter-organizational program administration team.
- Provide EDC with direct role in program and in MG project planning and development, and require microgrids to coordinate with the EDC on design and operations.
- Define microgrid and critical facility for program participation and project eligibility to utilize program-related enabling rules and exceptions.
- Develop and deploy a robust education program.
- Use project planning guides, and a detailed RFP / application that defines technical and economic requirements.
- Consider a two-tier process to provide high-level screen of feasibility analysis.
- Provide funding support for feasibility analysis.
- Prioritize energy efficiency and clean energy.
- Employ rolling application deadlines and/or allow several months for feasibility analysis and application development, especially for municipalities.
- Employ design and construction schedules with ample time and administrative flexibility. Application review, selection process & criteria.
- Provide streamlined or preferential administrative and permitting processes. Consider award disbursements based on milestones.
- Commissioning must be complete to receive full funding.
- Require performance evaluation and data monitoring and collection annually or in real time for contract term.

Section 2.4 Legislative measures: See this section for further discussion. Legislative actions that could support microgrid development include:

- Expand DG / DER program support.
- Include microgrids in RES or as a stand-alone mandate, with incentives.
- Enable approved microgrids to distribute power across public ROW and utility

easements. Create enabling structures to facilitate economical and legal and low-risk project development behind the meter (BTM).

Section 2.5 Regulatory measures and potential PUC actions: See this section for further discussion. Regulatory actions that could support microgrid development include:

- Require, incent or enable the EDC to provide information on potential locations for microgrid development of greatest value to the EPS.
- Require, incent or enable the EDC to create custom tariffs for cost recovery and/or rate risk reduction in microgrid locations, and/or for microgrids to monetize sources of value that they provide to the EPS and EDC.
- Require, incent or enable the EDC to procure energy from resilient islandable DERs.
- Require, incent or enable the EDC to use on bill financing for microgrid investments.
- Require, incent or enable the EDC to own or contract for generation and/or storage, in excess of 15 MW cap.
- Require, incent or enable the EDC to participate in utility-directed and/or hybrid microgrid models.
- Exempt microgrids from PUC regulation that are publicly-owned or below a size cap.
- Enable non-utility third parties to own and operate Level 3 multi-user microgrids.

APPENDIX A: RISKS TO THE RHODE ISLAND ELECTRIC GRID

See Appendix A for detailed discussion of specific hazards, each paired with policy recommendations to mitigate and/or adapt to the risks.

ABBREVIATIONS

ACEEE = American Council for an Energy-Efficient Economy
ACP = Alternative Compliance Payments
AGT = Algonquin Gas Transmission natural gas transmission pipeline
AHJ = Authorities Having Jurisdiction (over a regulated topic)
ASHRAE = American Society of Heating, Refrigerating, and Air-Conditioning Engineers
ATS = Automatic transfer switch
BC = Behavior Change (for EE)
BCV = PAG's Babcock Village property in Westerly, RI
BES = Battery energy storage
BMS = Building Management System ("controls")
BTM = Behind The Meter
BUG = Back-Up Generator
C-PACE = Commercial Property Assessed Clean Energy
CA = California
CAP = Climate Action Plan
CBA = Cost-Benefit Analysis
CBAM = Cost-Benefit Analysis Model
CDBG-DR = (HUD funded) Community Development Block Grant – Disaster Relief
CEMP = (State) Comprehensive Emergency Management Plan
CES = Comprehensive Energy Strategy
CF = Critical Facility
CFB = Circulating Fluidized Bed (coal plant technology)
CHP = Combined Heat and Power or cogeneration
CI = Critical Infrastructure
CIAT = Critical Infrastructure Assessment Tool (in RI CIPP)
CIKR = Critical Infrastructure and Key Resources (in RI CIPP)
CIP = Critical Infrastructure Protection
CIPP = Critical Infrastructure Protection Plan
CL = Critical Load
CME = Coronal Mass Ejection or solar flare
CNG = Compressed Natural Gas (for vehicles)
COO = Continuity Of Operations
COOP = COO Plan
COTS = Commercial Off The Shelf equipment
CSF = NIST's Cybersecurity Framework
C_x = Commissioning
D/B = Design / Build
D/B/B = Design / Bid / Build
DBOOM = Design, Build, Own, Operate, Maintain
DBT = Design Basis Threat
DER = Distributed Energy Resource
DER-CAM = LBNL's Distributed Energy Resources Customer Adoption Model software

DG = Distributed Generation
DHS = U.S. Department of Homeland Security
DHW = Domestic hot water for residential use
DoD or DOD = U.S.. Department of Defense
DOE = U.S. Department of Energy
DR = Demand Response (curtailable loads)
E1 = EMP very short duration pulse that can damage electronic equipment
E3 = EMP short duration pulse that can cause GMD and GIC
EDC = Electricity Distribution Company (*i.e.*, non-vertically integrated utility)
EE = Energy Efficiency (load reduction)
EIA = U.S. Energy Information Administration
EISC = Electric Infrastructure Security Council
EMA = (State or local) Emergency Management Agency
EMP = Electromagnetic pulse
EOC = Emergency Operations Center
EOP = (State) Emergency Operations Plan
EPC = Engineering, Procurement, Construction
EPFAT = Emergency Power Facility Assessment Tool (of FEMA and U.S. Army Corps of Engineers)
EPRI = Electric Power Research Institute
EPS = Electric Power System (*i.e.*, the "Grid" or "Macrogrid")
ES = Energy Storage
ESA = Energy Services Agreement
ESCO = Energy Services Company
ESPC = Energy Savings Performance Contract
EUI = Energy Use Intensity (kBtu/SF)
EV = Electric Vehicle
FC = Fuel cell
FEMA = Federal Emergency Management Agency
FERC = Federal Energy Regulatory Commission
FITC = Federal Investment Tax Credit
FTE = Full Time Equivalent employee(s) in labor hours
Genset = Generator set (*e.g.*, emergency or backup power, typically fossil fueled)
GHG = Greenhouse Gases (CO_2 & equivalent, as per CAP)
GIC = Geomagnetically-induced currents due to an EMP or CME
GIS = Geographic Information System software
GMD = Geomagnetic disturbance due to an EMP or CME
HHW = Heating hot water for hydronic system space heating
HILF = High-Impact, Low-Frequency (events that disrupt critical infrastructure)
HOMER = NREL's Hybrid Optimization of Multiple Energy Resources modeling software
HP = Horsepower
HUD = U.S. Department of Housing and Urban Development
HVAC = Heating, Ventilation and Air-Conditioning systems
HX = Heat exchanger
ICS-CERT = USDHS's Industrial Control Systems Cyber Emergency Response Team

IED = Improvised Explosive Device
IEMI = Intentional Electromagnetic Interference
ISO-NE = Independent Systems Operator-New England
IWG = Interagency Working Group
kBtu-hr = Kilo-(one thousand) Btu (British Thermal Units) per hour of thermal energy
kW or KW = Kilowatts or one thousand Watts
kWh or KWh = Kilowatt-hours of energy production or consumption
LBNL = USDOE's Lawrence Berkeley National Laboratory
LCOE = Levelized Cost of Energy
LDC = Local Distribution Company for natural gas
LMI = Low to Moderate Income demographic
LNG = Liquid Natural Gas
MA = Massachusetts
MACRS = Modified Accelerated Cost Recovery System accelerated depreciation schedule
MBH = Thousand Btu's per hour of energy output
MCO = Mission Critical Operations
MD = Maryland
MED = Major Event Day
MFH = Multifamily housing
MG = Microgrid
MMBtu or MBTU = Million British Thermal Units of heat energy content of fuel
MN = Minnesota
MT = Mass Transit
NEC = National Electrical Code
NERC = North American Electric Reliability Corporation
NFPA = National Fire Protection Association
NG = Natural Gas
NIAC = National Infrastructure Advisory Council
NIPP = National Infrastructure Protection Plan
NIST = National Institute for Standards and Technology
NJ = New Jersey
NM = Net metering
NPV = Net Present Value
NRC = Nuclear Regulatory Commission
NREL = USDOE's National Renewable Energy Laboratory
NY = New York
OA = Outside air
O&M = Operation and Maintenance
OER = Rhode Island Office of Energy Resources
OXP = POAH's Oxford Place property in Providence, RI
PAG = Property Advisory Group-Cathedral Development Group
PEM = Proton Exchange Membrane
POAH = Preservation Of Affordable Housing
PPA = Power Purchase Agreement
PV = Photovoltaic solar power

RCx = Retro-commissioning
RE = Renewable Energy
REC = Renewable Energy Credit (*e.g.*, 1 MWh of "green" energy attribute)
REG = RI's Renewable Energy Growth program
RES = RI's Renewable Energy Standard
RF = Radio Frequency
RGGI = Regional Greenhouse Gas Initiative
RI = Rhode Island
RICIPP = RIEMA's Critical Infrastructure Program Plan
RIEAP = Rhode Island Energy Assurance Plan
RIEMA = Rhode Island Emergency Management Agency
RIGIS = Rhode Island Geographic Information System
RIHMP = Rhode Island Hazard Mitigation Plan
RIIB = Rhode Island Infrastructure Bank
RIOER = Rhode Island Office of Energy Resources
ROW = Right Of Way or easement
RTO = Regional Transmission Operators
SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index
SBC = Systems Benefit Charges
SCADA = Supervisory, Control and Data Acquisition software
SF = Square foot or square feet
SIP = Shelter In Place
SIRI = Systems Integration Rhode Island planning process
SLA = Sector Lead Agency (in RI CIPP)
SLR = Sea Level Rise
SOO = Sequence Of Operations
SOW = Scope Of Work
SP = Sustainability Plan
SSP = Sector-Specific Plans (in RI CIPP)
ST = Solar thermal
T&D = Transmission and distribution electrical infrastructure
TELF = Tax Exempt Lease Financing
TELP = Tax Exempt Lease Purchase
TGP = Tennessee Gas Pipeline natural gas transmission pipeline
UA = Unique Asset
USDHS = U.S. Department of Homeland Security
USDOE = U.S. Department of Energy
USGCRP = U.S. Global Change Research Program
V = Volt
V2B = (Electric) Vehicle to Building relationship/connection
V2G = (Electric) Vehicle to Grid (electric or natural gas distribution system) relationship/connection
VFD = Variable Frequency Drive electric motor controller (see also VSD)
VNM = Virtual Net Metering

VSD = Variable Speed Drive Electric Motor Controller (see also VFD)
WT = Wind turbine

GLOSSARY

Ancillary Services: The Independent System Operator-New England administers competitive markets for services that are required to support the power system. The two most important are reserves and regulation. The reserves market pays resources (*e.g.*, generators) to be available to provide fast ramping power in the event of a unit or line trip. The regulation market pays resources to keep load and generation in constant balance by quickly adjusting their output/consumption in response to constantly changing load conditions (*e.g.*, a large load may decrease its consumption at a time when the system experiences low voltage, thereby restoring adequate voltage on the line).

ANSI-c84-1*:* American National Standard for Electric Power Systems and equipment, 2011 edition.

Anti-islanding: Safety protocols intended to ensure that distributed energy resources can't feed power onto utility distribution lines during a system outage. IEEE 1547 includes anti-islanding standards to protect the safety of utility line workers. (*See also "islanding.")*

Applicant: The entity that applies for a State microgrid program grant, *e.g.*, in response to an RFP or similar solicitation.

Backfeed: Flow of electricity in the opposite direction from usual flow.

Balancing: Active efforts to match energy supply and demand to maintain stable system operations -- pertinent for large-scale and small-scale grids. Microgrids can help transmission operators keep large grids balanced, and microgrids internally perform balancing services to operate in island mode.

Black start capability: A black start is the process of restoring a power generating system to operation without relying on the external electric power transmission network.

Building Energy Management Systems: A software control application that enables facility managers to configure, monitor, and automate HVAC, lighting, and programmable building devices.

Bulk energy (as in, bulk energy suppliers or bulk energy system): Bulk energy refers to power bought or sold on the wholesale energy market, defined below.

Capacity market: A market administered by the New York Independent System Operator designed to pay for sufficient resources (including traditional electric generators, but also demand response resources) to ensure that projected loads can be met on a long-term basis. This market matches buyers and sellers of capacity using the clearing price methodology.

Combined heat and power (CHP) (a.k.a., ”cogeneration”): Energy systems that supply both electricity and thermal energy from the same fuel source, thereby increasing energy efficiency. CHP systems could power microgrids at hospitals, institutional and corporate campuses, and some industrial sites.

Commercially Proven Technology*:* Technology, equipment or systems readily available on the commercial market. Does not include experimental or R&D technology.

Critical Facility: FEMA definition: “A structure or other improvement that, because of its function, size, service area, or uniqueness, has the potential to cause serious bodily harm, extensive property damage, or disruption of vital socioeconomic activities if it is destroyed or damaged or if its functionality is impaired. Critical facilities include health and safety facilities, utilities, government facilities and hazardous materials facilities. For the purposes of a local regulation, a community may also use the International Codes’ definition for Category III and IV buildings.” RIEMA definition: “Critical infrastructure includes those assets, systems, networks, and functions—physical or virtual—so vital to Rhode Island that their incapacitation or destruction would have a debilitating impact on security, economic security, public health or safety, or any combination of those matters.”

Demand Response: The New York Independent System Operator supports a number of programs designed to pay customers to undertake voluntary reductions of their load

Demand response (DR): Energy loads capable of being voluntarily reduced or curtailed under certain conditions in a given location based on price and reliability signals. If efficiency is the first step in designing a microgrid, then DR is the second.

Deployment costs: Deployment costs are a component of overall system costs. Deployment costs refer specifically to costs incurred in order to field the software or hardware components in the target system.

Distributed Energy Resource (DER): Smaller-scale power generation or storage. It is also known as Distributed Resources or Distributed Generation. End-use energy efficiency could also be considered a form of DER, particularly if the load reduction is dispatchable as in a demand response program.

Distributed Generation (DG): A generally small (up to roughly 50 MW) electric production facility that is dedicated to the support of nearby associated load. DG is the central asset in any microgrid.

EDC: Electric Distribution Company. An EDC manages the distribution (but not necessarily generation) between wholesale high voltage transmission to low-voltage end use. In Rhode Island, National Grid is the EDC serving almost the entire state, and generally does not own generation capacity with limited exception.

Electric Power System: All electrical wires, equipment, and other facilities owned or provided by the EDC or MEU that are normally operated at voltages below 69 kV to provide distribution service to customers.

Energy Improvement District (EID): A vehicle used by local and state governments to promote planning, development, and funding activities supporting energy infrastructure improvements in a defined geographic area or community. Community leaders could consider microgrids as part of Energy Improvement District planning.

Energy management system (EMS): Software and hardware for balancing energy supply (including storage) and demand to maintain stable operations. Smart grid EMS software established the IT framework for operating microgrids.

Energy service company (ESCO): A non-utility entity that provides retail, commercial, or industrial energy services. A microgrid service provider could be considered a type of ESCO, combined with a type of IPP.

EPA Tier (Diesels): EPA standard for off-road diesel exhaust emissions:

- **Tier 1** Emissions standard for engines manufactured between 1994 and 2001
- **Tier 2** Emissions standards for engines manufactured between 2001 and 2006
- **Tier 3** Emissions standards for engines manufactured between 2006 and 2008
- **Tier 4** Emissions standards for engine manufactured between 2008 and present.

EPC: Engineer, Procure, Construct. Normally is a single entity that has overall responsibilities for all of these activities related to a project.

Generation Controller: A hardware platform or software application that manages power generation components.

Generator: A device for producing electricity, and potentially useful byproduct thermal energy.

Hierarchical control scheme: A control scheme that distributes control authority and control actions vertically across layers. Usually a top layer, called master control, orchestrates the overall system control. Mid-tier layers coordinate groups and report back to the master control layer. The lowest layers control remote nodes in the system.

IEEE-1547: Institute of Electrical and Electronics Engineers, Standard for Interconnecting Distributed Resources with electric power systems. Incorporates by reference, IEEE-1547.4 – IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems.

IEEE-C62.41: Institute of Electrical and Electronics Engineers, Recommended Practices for Surge Voltages in Low Voltage AC Power Circuits.

IEEE-C62.45: Institute of Electrical and Electronics Engineers, Surge Testing for Equipment Connected to Low Voltage Power Circuits.

Interconnection Facilities: Include all facilities and equipment between the microgrid and the Point of Interconnection, including any modification, additions, or upgrades that are necessary to physically and electrically interconnect the microgrid to the EDC's Distribution System.

IPP: Independent power producers are non-utility companies that generate and sell energy to one or more customers. Most IPPs sell their output in wholesale markets, whereas microgrids serve retail customers directly.

Island Peak Load: Maximum operating electrical load of the microgrid when not connected to the utility grid. This load may be less than the normal facility demand, if some loads are intentionally removed from the distribution system for the duration of time when the microgrid is in island mode.

Island Mode or Intentional Islanding: Occurs when the microgrid has been isolated from the Electric Power System by planned operation of the disconnecting means consistent with its interconnection agreement. The microgrid DER(s) as a result is serving segregated load(s) on its microgrid's side of the Point of Interconnection.

Islanding: Intentional islanding is the act of physically separating a defined group of electric circuits from a utility system, and operating those circuits independently. Islanding capabilities are fundamental to the function of a microgrid. (*See also "anti-islanding."*)

Loop distribution system: A loop system, as the name implies, loops through the service area and returns to the original point. The loop usually ties into an alternate power source. By placing switches in strategic locations, the utility can supply power to the customer from either direction. See, by contrast, network and radial distribution systems.

MEU: Municipal Electric Utility.

Microgrid: A group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and that connects and disconnects from such grid to enable it to operate in both grid-connected or Island Mode.

Microgrid Controller: A hardware platform or software application that manages devices and operations in a Microgrid system.

Microgrid System Architecture: The end-to-end structural design and partitioning of a complete microgrid system. Defines the structure of hardware and software components, data, and interfaces.

MUSH: Military installations, universities, schools, and hospitals. Many of the first commercial microgrids are being installed for customers in MUSH applications.

New Load: Electrical load within one or more critical facilities that is presently supplied only with power purchased from the EDC with no emergency generator source, i.e. that portion of the facility load that does not receive power from an existing emergency generator during an emergency.

Net Metering: Net metering is a method of measuring the energy consumed by a customer and the surplus energy produced by a generator.

Network distribution system: Network systems are the most complicated distribution systems, as compared to loop or radial distribution systems. They can be thought of as interlocking loop systems. A given customer can be supplied from two, three, four, or more different power supplies. This system will provide the highest power reliability, and is more common in high load density or urban areas. See, by contrast, radial and loop distribution systems.

N+1: in power generation, ability for a generating plant to maintain normal operation after the failure of a single generator.

Net-zero: The condition in which a building or campus is capable of generating energy equal to its aggregate annual consumption. Some net-zero energy buildings can be upgraded to function as islandable microgrids.

One-Line Diagram: A diagram which shows, by means of single lines and graphic symbols, the course of an electric circuit or system of circuits and the component devices or parts used therein (as defined in IEEE 100 The Authoritative Dictionary of IEEE Standards Terms).

PACE Finance: Property Assessed Clean Energy Financing. This mechanism allows financing of energy efficiency upgrades or renewable energy installations for eligible buildings. In Rhode Island the Rhode Island Infrastructure Bank administers the Commercial PACE or C-PACE program. An eligible property owner can arrange financing for energy improvements, which is attached to the property via an assessment that is senior to mortgage (akin to a sewer lien). The loans are repaid over the assigned term (typically 15 or 20 years) via an annual assessment on their property tax bill. Host municipal governments process financing payments, then forward the funds on to the lender.

Parallel Mode: A Generating Facility that is electrically interconnected to a bus common with the EDC's or MEU's electric distribution system, and which operates in parallel either on a momentary or continuous basis.

Peak load support: Refers to the ability of generation assets to provide power during hours when energy demand is at its highest across a system. A microgrid may provide peak load support to the macrogrid, *e.g.*, by exporting power onto the macrogrid when the macrogrid is facing its highest demand period.

Photovoltaics (PV): Solar electric energy cells in any of numerous forms and configurations. Rapid advances in PV technology create opportunities for remote and cost-effective green microgrids.

Plug-in electric vehicle (PEV): Transportation vehicle with an onboard electricity storage system and the ability to charge from an outside power source. Campuses with charging stations for fleet PEVs (and employee cars) will integrate V2G as storage and balancing assets in microgrid systems.

Point of Interconnection: The point at which the microgrid's local electric power system connects to the Electric Power System, such as the electric power revenue meter or premises service transformer. Also referred to as the point of common coupling.

Power Factor: Ratio of real power (kW) to apparent power (kVA).

Power quality: The quality of electrical power may be described as a set of parameters, such as the continuity of the power service, or variations in voltage magnitude, under which electrical devices taking power off the system can function properly.

Pre-paid Power Purchase Agreement (PPA) model: A power purchase agreement is a type of financing where a third party owns and maintains the DER system, and the end user agrees to pay for that power over a given term (often 15-20 years). Sometimes, a PPA provider will offer the end user the option to pre-purchase all the energy the user is likely to require upfront in exchange for a particularly low rate.

Prime mover: Machine that converts thermal energy into mechanical motion used to drive a generator (engine).

Pro-Forma: Financial statement intended to show anticipated future financial performance of the project.

Radial distribution system: This distribution system connects multiple users to a single source of power. The distribution system runs from the power source and terminates at the end users, meaning any power failure on that line would cut off power supply to those customers. This system is widely used in sparsely populated areas. See, by contrast, network and loop distribution systems.

REC: Renewable Energy Credit. One REC equals one megawatt/hour of energy produced by a renewable source.

Sequence of Operations: An accounting of a system's procedures for start-up and shut-down, response to varying conditions, and certain scheduled operations.

Smart city: A community that plans and develops infrastructure, buildings, and operations to intentionally optimize efficiency, economics, and quality of life. Some smart city plans call for microgrids as part of special development districts with enhanced infrastructure services.

Smart grid: A energy system characterized by two-way communications and distributed sensors, automation, and supervisory control systems. Smart grid systems allow utilities to dispatch microgrids for grid balancing and ancillary services.

Spinning Reserve: That portion of the operating generator capacity held in reserve to accommodate momentary short duration surges in demand that occur as a result of motors starting and similar transients. Also, reserve to sustain short term overload for sufficient time to allow the load management system to respond, or additional generation to be brought on line.

Spot Network: A spot network is a small network typically with a nominal voltage of 480Y/277 volts in which the secondaries of two or more distribution transformers are connected to a common network bus through Network Protectors usually in a single location (see Interconnection Guidelines).

Switching infrastructure: The components in the electrical design that control and implement connect/disconnect/routing functions.

System integration: Part of the overall system design process, referring to the testing and validating of the interoperability of the various software and hardware components that compose the system.

Transactive energy: A market system in which retail energy consumption and supply decisions are driven by competitive market pricing, through a combination of long-term contracts and spot- and forward-market bids and tenders. Microgrids and their component nodes could be managed as part of a transactive energy system.

Transfer trip: A transfer trip is a protection system that sends a trip command to remote circuit breakers when an electrical fault is detected, thereby helping isolate and clear the fault.

Transmission and Distribution (T&D) investment deferral: Electric transmission and distribution systems require periodic upgrades in order to meet increasing demand. T&D investment deferral refers to the benefit microgrids may provide to the utility by reducing the load that the utility must serve in a given area, thereby potentially allowing the utility to make less short-term investment in upgrading its distribution system in that area.

Urban secondary network system: A secondary network system refers to the low-voltage circuits supplied by the network units (the network transformer and its associated network protector).

Urban spot network: A secondary network distribution system that consists of two or more network units at a single site. The secondary network-side terminals of these network units are connected together with bus or cable. The resulting interconnection structure is commonly referred to as the paralleling bus or collector bus. In spot networks, the paralleling bus does not have low-voltage ties to adjacent or nearby networks. Such spot networks are sometimes called isolated spot networks to emphasize that there are no secondary voltage connections to network units at other sites.

Utility tie point, or, point of common coupling: The point at which the interconnection between the electric utility and the customer interface occurs.

V2G: Vehicle-to-grid technology, integrating PEVs together for dispatchable electricity storage for grid support and ancillary services. EVs will provide storage capacity for microgrids through V2G technology.

Virtual Net Metering: Virtual net metering allows the production from a renewable energy resource to be allocated to multiple public sector metered accounts.

Virtual power plant (VPP): Aggregated power generating capacity that's provided by multiple, real DG facilities operating in different locations. Some microgrid DG systems could run in VPP clusters.

Wholesale energy market: A market for the sale of large quantities of electricity (1 MW or greater), which is provided from high-voltage transmission lines. This market is operated by the Independent System Operator-New England, and provides power to registered market participants, which include investor-owned utilities.

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